COMMONWEALTH OF PENNSYLVANIA

June 7, 2022

The Honorable Christopher P. Pell
Deputy Chief Administrative Law Judge
Commonwealth of Pennsylvania
Pennsylvania Public Utility Commission
801 Market Street, Suite 4063
Philadelphia, PA 19107

Re: Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc. 2022 Base Rate Filing / Docket No. R-2022-3031211

Dear Judge Pell:

Enclosed please find the Direct Testimony and Exhibits of Robert D. Knecht and Mark D. Ewen, labeled OSBA Statement No. 1, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney I.D. No. 77538

Enclosures

cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Robert D. Knecht
Mark Ewen
Parties of Record

OSBA Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2022-3031211**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

Direct Testimony and Exhibits of

MARK D. EWEN and

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Context
Context for Rate Increase
Cost Allocation
Revenue Allocation
Rate Design
Rate Decoupling/RNA

Date Served: June 7, 2022

Date Submitted for the Record: August 3, 2022

DIRECT TESTIMONY OF MARK D. EWEN and ROBERT D. KNECHT

1. Introduction and Context

Q. Mr. Ewen, please state your name and briefly describe your qualifications.

A. My name is Mark D. Ewen. I am a Principal of Industrial Economics, Incorporated ("IEc"), a consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140. My consulting practice focuses on regulatory and environmental economics, expert case management and economic damages estimation in a variety of litigation contexts, and financial analysis. I obtained a B.A degree in Economics and Political Science from the University of North Dakota, and a Master of Public Policy degree from the University of Michigan. My résumé and a listing of the expert testimony that I have filed in various litigation and utility regulatory proceedings are attached in Exhibit IEc-1.

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I am an independent economic consultant, specializing in the preparation of analysis and expert testimony in the field of regulatory economics. For more than 30 years, I was a Principal of Industrial Economics, Incorporated ("IEc"), a consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140, and I served as Treasurer of that firm for 15 years. I obtained a B.S. degree in Economics from the Massachusetts Institute of Technology in 1978, and a M.S. degree in Management from the Sloan School of Management at M.I.T. in 1982, with concentrations in applied economics and finance. My résumé and a listing of the expert testimony filed in utility regulatory proceedings during the past five years are included in Exhibit IEc-1.

I submitted testimony in the base rates proceedings involving Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company") in 2008 (Docket No. R-2008-2011621), 2010 (Docket No. R-2009-2149262), 2011 (Docket No. R-2010-2215623), 2012/2013 (Docket No. R-2012-2321748), 2014 (Docket No. R-2014-2406274), 2015 (Docket No. R-2015-2488056), 2016 (Docket No. R-2016-2529660), 2018 (Docket No. R-2018-2647577) 2020 (Docket No. R-2020-3024296) and 2021 (Docket No. R-2021-3024296). I also submitted testimony in a variety of Section 1307(f) and other proceedings involving the Company over the past decade.

Q. Please describe your assignment in this matter.

A. We are appearing in this proceeding on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA"). The OSBA requested that we review the Company's filing in this proceeding to evaluate whether the rates proposed for small business customers are consistent with sound economics and regulatory principles. Our analysis focuses primarily on issues of cost allocation, revenue allocation and rate design. If we have not addressed a particular issue, it cannot be inferred that we agree with Columbia's proposal for that topic.

Q. Please provide some background regarding the Company's filing, in the context of recent base rates proceedings.

A. Since 2008, Columbia has submitted eleven base rates filings. Prior to 2008, Columbia had not filed a base rates case since 1995. This steady flow of rate cases has been primarily driven by the Company's mains and services replacement program, undertaken over the past fifteen years. A summary of the base rates filing amounts and settlement rate increases is shown in Table IEc-1 below.

Table IEc-1
Recent Columbia Base Rate Increase Cases

Docket No.	Test Year Ending	Proposed Increase ($mm)	Award Amount ($mm)	Award Percent
R-2008-2011621	Sep-2008	$58.9	$41.5	71%
R-2009-2149262	Sep-2010	$32.3	$12.0	37%
R-2010-2215623	Sep-2011	$37.8	$17.0	45%
R-2012-2321748	Jun-2014	$77.3	$55.3	72%
R-2014-2406274	Dec-2015	$54.1	$32.5	60%
R-2015-2468056	Dec-2016	$46.2	$28.0	61%
R-2016-2529660	Dec-2017	$55.3	$35.0	63%
R-2018-2647577	Dec-2019	$46.8	$26.0	56%
R-2020-3017206	Dec-2021	$100.4	$63.5	63%
R-2021-3024296	Dec-2022	$98.3	$58.5	60%
Total		**$607.4**	**$369.3**	**61%**
R-2021-3024296	Dec-2023	$82.2	--	--

Columbia's relatively large increase in the R-2012-2321748 proceeding was due in part to the switch to using a fully forecasted future test year approach, thereby incorporating nearly three full years of (mostly forecast) capital expenditures in the mains replacement program since the prior base rates case.

As is apparent in the table, the Company's cost requirements have accelerated, with relatively large increases being proposed in each of the past three rate cases. Columbia has justified these accelerating costs and aggressive pipe replacement efforts in part on customer affordability grounds, noting: "It makes sense to do it now before the pipe fails, and since gas prices remain relatively low in Pennsylvania, in addition to reducing risk by replacing this pipe now, the customer's total gas bill will continue to be affordable."[1] With natural gas futures prices for next winter in the $8.30 to $8.60 per million btu range, this assertion is tenuous at best.[2] We respectfully disagree with Columbia that accelerating pipeline replacements on the basis of current commodity prices represents a reasonable strategy.

With its proposed increase, Columbia now has the dubious distinction of having the highest residential and small commercial base rates among large natural gas distribution companies ("NGDCs") in the Commonwealth.[3]

Q. Is there an end in sight for these regular large base rate increases?

A. Based on what is currently proposed in Columbia's Age and Condition Program, it does not appear so. Specifically, approximately 38.5 percent of the Company's distribution pipeline infrastructure remains targeted for replacement. Over the next ten years, it has budgeted for over $2.7 billion in expenditures for mains replacement alone. At its projection of an average replacement rate of 100 miles a year, it would take a minimum of 30 years to complete the entire implementation of its infrastructure replacement program.[4]

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[1] Columbia Statement No. 1 at 15.

[2] https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.settlements.html last revjewed 5 June 2022.

[3] See IEc WP1, "Rate Comp" worksheet.

[4] OSBA I-5.

The cost for this enormous physical replacement requirement is compounded by the rapidly increasing cost per mile to replace mains, reflecting a variety of factors not least of which is the burgeoning demand for qualified contractors from all Pennsylvania NGDCs. Between 2008 and 2021, the cost to replace a foot of pipe has increased from $81.25 to $238.00, a near tripling of the cost.[5] Cost per foot forecasts increase to $277 in 2023 and continue to grow over the next ten years.[6]

Q. Will the Company be able to fully recover its allowed rate of return on this massive capital spend over the longer term?

A. We do not know. We all recognize that there are growing societal and political concerns regarding the burning of fossil fuels, and there is concomitant increasing pressure for electrification, not only in transportation but in home heating. For the past fifteen years, the Company's declining distribution cost competitiveness has been rescued by the hydraulic fracturing boom and the resulting decline in natural gas commodity prices. This environment of low commodity costs may be changing with the expansion of US LNG export capacity. At a minimum, commodity price volatility is likely to increase. If Columbia's distribution rates continue to grow at the historical rate, heating alternatives like heat pumps and mini-splits will become more economically attractive to customers. In addition, the potential remains for increased regulation of CO_2 emissions for both gas consumers and gas producers, both of which could further increase the cost of gas.

In this light, it is somewhat surprising that the Company does not appear to conduct thorough longer-term financial forecasts to evaluate these issues. For example, the Company has only looked at the operating costs of typical natural gas furnaces compared to electric heat pumps and resistance furnaces for residential use (which shows heat pumps already being cost competitive with gas at higher system efficiency levels).[7] The Company represents that it

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[5] Columbia Statement No. 7 at 13.

[6] OSBA-I-8 and OSBA-I-7.

[7] OSBA-I-6. It is unclear whether Columbia's analysis reflects the current market commodity prices for natural gas.

has not done any analysis of mini-splits for residential customers, nor has it conducted any competitive analysis concerning gas alternatives for small commercial customers.[8]

Q. What are the implications of these trends for the current rate proceeding?

A. Given the lack of a long-term competitive analysis of its distribution business, we do not believe that the Company has demonstrated that its overall capital spending plan is prudent. While we cannot comment on the legal issues, we believe the Commission should advise Columbia that future capital expenditures have not been shown to be part of a demonstrably prudent long term investment plan, and that they can be subjected to *ex post* prudence reviews should they become stranded. At a minimum, we believe the Commission should require Columbia to demonstrate that it has a long-term viable business as part of its next LTIIP filing.

Q. Do you have any preliminary general comments regarding cost allocation and rate design in this proceeding?

A. We do. In the Company's base rates proceeding at Docket No. R-2020-3017206, the Commission approved the use of a "peak-and-average" ("P&A") method for mains cost allocation. Also in that proceeding, the Commission accepted the Company's position with respect to negotiated rate revenues from its "flex" rate customers.[9] For the current proceeding, these decisions have three significant impacts.

First, the costs allocated to the regular rate larger industrial customers in the Rate LDS class are roughly double the revenues currently recovered from that class, a shortfall of more than $20 million.[10] Moving rates reasonably into line with allocated cost for this class cannot be achieved in a single proceeding, and thus much of this shortfall must be borne by other

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[8] *Id.*

[9] Opinion and Order, Pennsylvania Public Utility Commission, Docket No. R-2020-3017206, Order Entered February 19, 2021, pages 211-218 and 240-241.

[10] These values are based on the Company's cost allocation study, and do not reflect any provision for the LDS class to contribute to the shortfall from flex rate customers. See IEc WP2.

classes. Moreover, this class can reasonably expect significant rate increases on top of the system average base rate increases for the foreseeable future.

Second, the costs allocated to negotiated "flex" rate customers are more than nine times higher than the revenues generated by these customers, under the negotiated rate agreements that were generally approved by the Commission in the 2020 base rates case. This results in a shortfall of $34 million, none of which can be recovered from the flex rate customers due to the negotiated contract rates.[11] This shortfall must therefore be reassigned to the other rate classes, including the regular rate LDS customers.

Third, because no mains costs are classified as customer-related, the customer portion of allocated costs is materially lower than that presented in previous cost evaluations. This change reduces the potential for cost-based customer charge increases, particularly for non-residential rate classes.

2. Review of Columbia's Non-Residential Rate Classes

Q. Before getting into the details of your analysis, please summarize the rate classes under which businesses take service from Columbia.

A. Columbia's tariff has a number of schedules under which non-residential customers take service. These tariff schedules are generally distinguished by size of customer (as measured by annual throughput) and type of service. Service types include the following:

- Sales service, in which customers procure both gas supplies and distribution service from Columbia;
- Retail transportation "Choice" service, in which smaller customers can purchase gas supply from NGSs and purchase both bundled load balancing services and distribution services from Columbia;

[11] These values are based on our alternative version of the Company's cost allocation study, because the Company admits that its study has a material error regarding allocation to flex rate customers. See Section 4 below.

- Transportation service, in which larger non-residential customers purchase gas supplies from NGSs, purchase load balancing services as needed from Columbia and/or their NGSs, and purchase distribution service from Columbia.

For cost allocation purposes, Columbia aggregates these disparate rate classes into rate class groups.

In total, the non-residential rate classes represent about 58 percent of Columbia's total throughput, or about 48 million of Columbia's total 83 million Dth in the test year. Customer size varies widely, ranging from small businesses that consume less than 10 Dth per year to very large industrial customers with more than 1,000,000 Dth per year.

The following are the non-residential rate class groups specified by Columbia for its cost allocation analysis. Because the Company's abbreviations for the rate class groups are somewhat contradictory, we include descriptive names for these groups.

SGSS/SCD/SGDS ("Small General" or "SGS"): This group consists of three tariff schedules: Small General Sales Service ("SGSS"), Small Commercial Distribution ("SCD"), and Small General Distribution Service ("SGDS"). To reflect the range of costs associated with serving these diverse classes, Columbia has adopted differentiated customer and commodity charges for customers in this group of classes, split between customers with annual consumption above and below 644 Dth. Maximum annual throughput for this class is 6,440 Dth/year. Consistent with recent past practice, the Company separates these two groups for both cost allocation and rate design purposes. We refer to the customers with annual consumption below 644 Dth as "SGS1," and the larger customers as "SGS2."

Within these two rate class groups, SGSS is sales service, SCD is retail "Choice" transportation service and SGDS is regular transportation service.

In the SGS1 group, about 70 percent of the load is to sales customers, implying a shopping rate of 30 percent, which is materially higher than the residential shopping rate of 12 percent. The average SGS1 customer size is about 185 Dth per year, which is a little more than double the size of the average residential customer. Of the shopping customers in this group, over

80 percent of the load is in the Choice program. Overall, this class represents about 12 percent of the Company's non-residential throughput.

In the SGS2 group, about 44 percent of the load relates to sales customers, with the majority of SGS2 shopping customers using traditional transportation service. The average SGS2 customer size is 1,704 Dth/year, which is about 9 times the size of the average SGS1 customer. Overall, this class represents 18 percent of the Company's non-residential throughput.

SDS/LGSS ("Medium General"): This rate class group includes both sales and transportation service customers, taking service under Rate Schedules LGSS (sales service) and Small Distribution Service ("SDS") (transportation service). Columbia's "Small" designation for the transportation customers in this tariff category is misleading, as the *minimum* throughput is 6,440 Dth per year, matching the *maximum* size requirement for the Small General customers. The maximum annual throughput for this class is 54,000 Dth per year, with an average annual customer throughput of about 15,600 Dth. This rate class group (excluding the flex rate customers) represents about 14 percent of non-residential throughput.

LDS/LGSS ("Large General"): This class includes the larger sales customers in the LGSS class along with the transportation service customers taking service under Rate Schedule Large Distribution Service ("LDS"). Minimum throughput is 54,000 Dth per year, matching the Medium General Service upper limit. A significant share of the volume for this rate class is included in the "Flex" rate class category for cost allocation, revenue allocation and rate design purposes.

MDS ("Mainline"): Customers in this rate class group take service under Rate Schedule Main Line Distribution Service ("MDS").[12] To be eligible for this service, customers must have annual throughput over 27,400 Dth, *and* be directly connected to an interstate pipeline (Class I), *or* have a minimum annual demand of 214,600 Dth *and* be located within two

[12] Columbia's tariff includes a Main Line Sales Service schedule, but no customers currently take service under that schedule.

miles of an interstate pipeline interconnection (Class II). Because these customers require very little in the way of distribution facilities, and because Columbia reports that they are credible "bypass" threats, Columbia uses different cost allocation and rate design methods for this rate class group.

Consistent with recent practice, the Company does not treat large general sales service ("LGSS") customers as a separate rate class for cost allocation purposes, and it includes those customers with transportation customers of comparable size. Sales customers taking service under Rate LGSS are free to switch to the comparable transportation service schedule, and, generally, vice versa. Thus, it is reasonable that the distribution rates for all customers of a similar size be the same, to avoid distorting the decision to shop. Since the distribution rates are the same, there is no need to separately allocate costs. Moreover, the total load associated with Rate LGSS is relatively small, since most large customers directly procure natural gas supplies.

Finally, the tariffs for the Company's larger rate classes allow for discounted, negotiated "flex" rates, for customers who have the potential to economically use an alternative fuel or to bypass the distribution system to interstate pipelines or local supply. Rates for these customers are therefore set based on market conditions rather than utility cost to serve. To allow the Company to set regular tariff rates based on allocated cost, the customers who currently have flexed rates are segregated into a separate class for cost allocation purposes.

3. <u>Flex Rate Customers</u>

Q. Please summarize the economic and regulatory issues surrounding Columbia's "flex rate" customers.

A. In general, utility tariff charges are set based on allocated cost of service and other rate design criteria, and these tariff charges apply to all customers within the rate class. However, under certain conditions, it can be beneficial to all parties to allow the utility to negotiate rate discounts from the regular tariff rates to retain customers who have lower-cost competitive options. These options include alternative fuel, pipeline bypass, and in the case of western Pennsylvania, "gas-on-gas competition" from other natural gas distribution companies

("NGDCs").[13] The specific criteria where negotiated discounts are in the interests of all ratepayers are:

- Negotiated rates exceed the incremental cost of providing service to the customer. Thus, for example, if Columbia needs to upgrade its distribution system to continue to provide service to a flex rate customer, the negotiated rates must be sufficient to justify that expenditure.

- In the case of alternative fuel competition, negotiated tariff rates plus the cost of gas should be set at or near the full delivered cost of the alternative fuel plus the customer's costs of conversion.

- In the case of pipeline bypass, negotiated tariff rates are justified only if there is a credible engineering plan for how the customer could physically bypass the NGDC. If that criterion is met, the negotiated tariff rate plus the cost of gas should be set at or near the customer's full cost for bypassing the NGDC and taking service directly from the pipeline. This cost necessarily includes obtaining the necessary permits to allow for such bypass.

- In the case of NGDC "competition," the Commission has determined that where customers are served in overlapping NGDC service territories, the minimum flex rate that can be charged is the lowest regular tariff rate of the NGDCs serving the customer's location.[14]

Q. Please summarize the positions of the parties and results of recent base rates proceeding regarding flex rates.

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[13] NGDCs do not "compete" for customers in overlapping service territories on the basis of cost or service. They have historically "competed" on the basis of which NGDC can offer the largest rate discount to those customers who have options and pass the cost for those discounts on to captive customers who do not have options.

[14] *Opinion and Order,* Pennsylvania Public Utility Commission, Docket Nos. P-2011-2277868 and I-2012-2320323, Order Entered May 4, 2017, page 52. To our knowledge, there has not been a firm resolution as to how the lowest applicable tariff rate should be defined. See *Opinion and Order,* Pennsylvania Public Utility Commission, Docket Nos. P-2011-2277868 and I-2012-2320323, Order Entered June 13, 2019.

A. In its 2020 base rates case, Columbia Gas argued that its negotiated rate revenues for flex rate customers reasonably represented the maximum revenues that the Company could earn from those customers given competitive conditions. The Company therefore argued that those rates were reasonable, and that no portion of the rate increase could be assigned to those customers. Mr. Knecht countered that the Company failed to demonstrate that some of the claimed flex rates were justified, and that appropriate additional revenues should be assigned to flex rate customers.[15] No other witnesses have formally challenged the magnitude of the Company's flex rate discounts, nor have they been disallowed or adjusted by any recent Commission order.

The Company is obligated, however, to update a competitive alternative analysis for any customer that has not had its alternative fuel source verified for a period of ten years. This decennial review requirement was implemented under Commission order for Docket No. R-2020-3017206.

Q. Did the Company file the competitive analysis approved by the Commission?

A. The Company's position is that it conducts individual reviews of flex rate customers on a rolling basis and is compliant with the terms of the decennial review requirement. As a result, however, for many flex rate customers the vintage of the existing competitive analysis can be quite dated. This situation has obvious implications for revenue allocation, (as the revenue shortfall from flex rate customers must be recovered from other rate classes) and is particularly relevant as Columbia continues to operate in a more uncertain environment for commodity prices and gas demand.

Q. Given your concern about out-of-date competitive analyses, do you have a recommendation?

A. Yes. We recommend that the Company conduct the competitive alternatives analysis for each flex rate customer every two years.

Q. What are the implications of the flex rates for the Company's revenue requirement in this proceeding?

[15] OSBA Statement No. 1-S at 5, Docket No. R-2020-3018835.

A. Based on our cost allocation analysis, the costs allocated to flex rate customers are $34 million higher than current negotiated rate revenues.[16] This shortfall must be recovered from the other rate classes.

4. Cost Allocation

Q. What is the purpose of a utility's allocated cost of service study ("ACOSS")?

A. The primary criterion for setting regulated utility rates is the cost incurred by the utility for providing the service.[17] To assign costs to specific customers, utilities aggregate customers into rate classes, within which the customers have similar load sizes, seasonal consumption, peak demand patterns, and other characteristics. An ACOSS is an analytical tool with which the utility's total cost (or "revenue requirement") is allocated among each of the rate classes. These allocated costs are then used as a key input in determining the total revenues that the utility plans to recover from each rate class through tariff rates.

In using the results from an ACOSS to develop class revenue requirements, utilities and regulatory authorities usually have a longer-term goal of moving the revenue recovered from each class as close as possible to the costs allocated to that class. That is, in each proceeding, regulators try to move class revenues more into line with cost-based rates. Thus, rate classes whose revenues substantially exceed allocated costs are assigned either relatively low rate increases or rate decreases. Rate classes whose revenues are well below allocated costs are assigned larger rate increases than those classes whose revenues are only slightly below allocated costs.

In addition to class revenue requirement issues, an ACOSS can provide useful cost information regarding the specific nature of utility tariff charges. In particular, an ACOSS provides a cost basis for the relative magnitude of the various individual tariff charges, including the customer charge, demand charges, and commodity charges.

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[16] See IEc WP3.

[17] The Commonwealth Court affirmed this basic principle, referring to cost of service as the "polestar" criterion. Lloyd v. Pennsylvania Public Utility Commission, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006).

Q. How does an ACOSS assign costs to the various rate classes?

A. The underlying principle of an ACOSS is that costs are assigned to the rate classes that *cause* the utility to incur those costs. This principle of cost causation is both equitable and economically efficient. It is equitable because costs are borne by those customers who cause them. It is economically efficient because the price signal for consumption from a particular rate class is reasonably consistent with the cost incurred by the utility to provide the service. In that way, the consumer receives the correct price signal for determining whether to purchase more or less of the utility service. In effect, the consumer balances the value received from the purchase of that service against the utility's cost of providing the service.

Q. What is the Company's approach to cost allocation in this proceeding?

A. With its filing, the Company presented three detailed cost allocation studies, in Exhibit 111 Schedules 1, 2 and 3. The Company's cost allocation analysis is supported by Witness Kevin L. Johnson, Columbia Statement No. 6.

Q. Why does the Company present three different cost allocation studies?

A. The Company has consistently submitted two alternative ACOSS models in its base rates filings stretching back to at least 2008, with a third version that is an average of the two. The models differ only in how mains plant costs are classified and allocated.

The "CD" model classifies and allocates mains costs using a "minimum system" method, in which costs are segregated into a "customer component" and a "demand component." The customer component of costs is derived based on the cost of installing the minimum size pipe throughout the current distribution system, and those costs are allocated based on number of customers. The minimum system construct is designed to reflect the economies of scale of serving and interconnecting larger customers. The remaining costs are deemed to be demand-related, meaning that the costs are causally related to customer's maximum rate of system usage. Demand-related costs are allocated based on a measure of class peak demand (usually "design day" demand for NGDCs), to reflect the fact that each main must be sized to be able to meet the peak demands of downstream customers under extreme weather conditions.

The Company's "P&A" model allocates all mains costs based on a 50/50 weighting of average demand and design day peak demand.[18] Advocates for this method argue that there are no scale economies to attaching and serving larger customers, and that a portion of mains costs are causally related to annual throughput.

The Company's "AVG" model is a simple average of these two methods. It should be recognized that the Company's two methods produce enormously divergent results.

In the Company's 2020 base rates case, however, Pennsylvania Office of Consumer Advocate ("OCA") Witness Jerome D. Mierzwa generally argued that (a) the results of the CD method were irrelevant to cost causation, and (b) segregating mains costs by operating pressure was not appropriate (except for mains operating at transmission pressure). The Commission approved Witness Mierzwa's approach. The Company indicates that it now conceptually agrees with Witness Mierzwa that there is no need to segregate mains by operating pressure, although Witness Johnson argues that this change is justified by the Company's mains replacement program which allows smaller customers to be served from higher pressure plastic pipe.[19]

As we indicated earlier, mains costs allocated to the MDS class are not affected by these alternative allocation methods. MDS customers are either attached directly to the interstate pipeline system or are in close physical proximity. The cost for the mains used to supply these customers are directly assigned to that class, and thus are the same in all ACOSS model simulations.

The Company indicates that it generally relies on the P&A ACOSS for revenue allocation and rate design in this proceeding, although the Company appears to believe that the results of the CD ACOSS have some relevance.[20]

Q. What approach do you take for cost allocation in this proceeding?

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[18] From a cost allocation perspective, "average demand" is arithmetically equivalent to annual throughput.

[19] Columbia Statement No. 6 at 8-9.

[20] Columbia Statement No. 6 at 17-18.

A. While we disagree with the Commission's findings regarding mains cost allocation in the 2020 base rates case, we accept the method employed by the Company in its P&A ACOSS for reasons of Commission precedent. Litigating this issue annually serves no useful purpose. The issue at hand is to incorporate the implications of that decision into rates as quickly as is practicable, subject to the constraints of rate gradualism.

As a practical matter, we replicated the results of the Company's P&A ACOSS in our own version of the ACOSS. Because the Company's method generally appears to be consistent with that used in the last case, and because that method was approved by the Commission just four months ago, we did not conduct an exhaustive review of all aspects of the cost allocation study.

However, in comparing the P&A ACOSS filed in this proceeding with that submitted in the 2021 base rates case, we identified a material change in the design day demand allocation factor. Also, in replicating the Company's ACOSS, we flagged three technical errors in the ACOSS that should be corrected.

Finally, the enormous revenue shortfall from the flex rate class makes revenue-cost comparisons difficult. To address that issue, we apportion the flex rate shortfall among the various other rate classes as part of our cost allocation analysis.

These changes are reflected in our alternative P&A ACOSS, detailed in IEc WP3.

Q. Please describe your concern regarding design day demands.

A. To develop the "peak" component of the P&A allocation factor, natural gas distribution companies ("NGDCs") generally rely on an estimate of "design day" demand, which reflects the capacity that the NGDC must provide to ensure that it can meet its delivery obligations under extreme weather conditions. For large, daily-metered customers, design day demand will usually reflect the customer's contract demand, or it may be based on an estimate of demand under extreme conditions based on a statistical analysis of historical daily-metered values. For the smaller customers classes as a group, the NGDC can develop daily historical demands by subtracting the daily metered demands of larger customers from the daily total sendout measured at the city gates. It can then use those daily demands to statistically estimate design day requirements for small customers in total. However, to develop design day demands for each individual rate class (i.e., to distinguish between residential and small/medium commercial classes), the NGDC must generally rely on weather-sensitivity analyses of monthly data.

In reviewing the Company's throughput and design day demands in this proceeding, we identified what appears to be a significant shift in either the behavior of customers or in the Company's method for deriving design day demands. Table IEc-2 below compares the factors from the last case to the present one. The table shows the changes in class throughput, class design day demand, and class load factor for the small and medium volume rate classes, where contract demands and daily metering are generally not available.[21]

Table IEc-2
Shifts in Columbia Volume and Design Day Demand Factors

	Residential	SGS1	SGS2	SDS/LGSS
Throughput: 2021	34,643,463	5,655,506	8,993,139	7,494,851
Throughput: 2022	35,096,960	5,891,881	8,873,377	6,997,482
Percent	1.3%	4.2%	-1.3%	-6.6%
Design Day: 2021	465,000	77,700	101,000	55,900
Design Day: 2022	448,800	87,000	106,200	65,877
Percent	-3.5%	12.0%	5.1%	17.8%
Load Factor 2021	20.4%	19.9%	24.4%	36.7%
Load Factor 2022	21.4%	18.6%	22.9%	29.1%

Source: IEc WP3

As shown, the residential class exhibits a 1.3 percent increase in load, but a 3.5 percent *decrease* in design day demand. The SGS2 and SDS/LGSS classes exhibit the reverse

[21] Load factor is a measure of how level gas usage is over the year and is defined as average day demand divided by peak day demand. A customer that uses the same amount on every day has a 100 percent load factor. For temperature sensitive loads that are dominated by space heating requirements, load factors are relatively low.

pattern, with loads falling but design day demands rising. The SGS1 class exhibits a modest increase in load, but a large increase in design day demand.

Since the weather responsiveness of rate class demand is unlikely to shift so significantly in a one year period, these data imply that the Company has changed its methodology for deriving design day demands for these classes. Moreover, since the overall design day demand within these classes does not shift significantly between the rate cases, it would appear that the Company has made a change to how it subdivides its design day demands for small customers among the various rate classes.

We note also that it is unusual for the load factor for the small commercial class to be materially below that of the residential class.

Q. How does the Company explain these shifts?

A. The OSBA put that question to the Company in OSBA-II-1. From the response, it appears that at least some of the increase in the SDS/LGSS design day demand results primarily from an error in the last case, in which design day demands for Standby Service and Elective Balancing Service were inadvertently excluded from the allocation factor. However, the Company offers no explanation for the significant reduction in load factor from the prior case for the SGS1 and SGS2 classes, nor does it take notice of the increasing load factor for the residential class.

Q. Have you reviewed the Company's workpapers for deriving design day demand?

A. Workpapers were requested in OSBA-II-1. However, the workpapers provided in that response consisted only of summary values, with no details regarding the development of the design day demands.

We also reviewed the design day demand forecasts provided in the Company's current Section 1307(f) proceeding. As detailed therein, the Company uses a geographically detailed methodology to derive design day demands using extreme temperature and wind conditions for the non-daily metered customers (i.e., all residential, small commercial and medium commercial customers) as a single group. The Company then reports, *"In Step 3, the remainder of Firm Demand (Firm Demand less Industrial Firm Demand less Company*

Use, and Unaccounted-For Gas) is allocated to Residential and Firm Commercial based on the forecasted demands from the Gas Estimate, inclusive of Choice." Unfortunately, the Company offers no explanation for how that allocation is made, or whether it reflects the relative weather sensitivity of the various classes, or why the allocation changed so significantly between 2021 and 2022.

Q. Is the allocation of design day demand among the smaller customer classes an important factor in a Section 1307(f) proceeding?

A. No. The design day demand consideration in the Section 1307(f) proceeding is whether the Company has sufficient capacity to meet the design day demands of its gas supply customers in total. It matters little how design day demands for the small customers in general are allocated among the various small customer classes.

Q. Is it possible that the Company simply corrected a previous error in its 2022 Section 1307(f) proceeding and that the current values are more accurate?

A. It is possible, but we deem it unlikely. First, as we noted earlier, it is unusual for the small commercial load factor to be materially below the residential class load factor. Second, we reviewed the monthly load forecast used in the current proceeding for the FPFTY. That analysis is shown in IEc WP4. In that workpaper, we prepared a statistical analysis of the monthly loads and monthly heating degree days, and we simulated implied design day demands based on that analysis. That workpaper shows that the Company's monthly load forecast for the FPFTY indicates that load factors for the Residential and SGS1 classes should be similar in magnitude, and that the SGS2 class load factor should be materially higher. Thus, we conclude that the Company's design day demands are not consistent with the Company's load forecast.

Q. How have you modified the Company's ACOSS for this analysis?

A. In IEc WP3, we reallocated the design day demand for the Residential, SGS1 and SGS2 classes to reflect our statistical analysis of the Company's FPFTY load forecast. This change has the effect of producing load factors for those classes that are reasonably similar to those used in the Company's last base rates case.

Q. What technical corrections have you made to the Company's ACOSS?

A. We made the following changes:[22]

- Pursuant to the Company's response to OSBA-II-2, we modified the volume value for Flex rate customers for mains allocation to correct the error acknowledged by the Company. This change has a material impact on costs allocated to the flex rate class, reducing the revenue requirement at proposed rates by approximately $7 million.

- Pursuant to the Company's response to OSBA-II-4, we adjusted the services allocator for the SGS1 and SGS2 class to exclude two high-cost service lines from the allocator that do not apply to customers in that class.

- Pursuant to the Company's response to OSBA-II-5, we corrected a summation error in the Company's ACOSS, which has a *de minimis* impact.

Q. Please discuss your treatment of the flex rate shortfall.

A. As we discussed earlier, the subsidies provided to the flex rate customer group at current rates dwarf that class's current revenues and represent by far the largest revenue shortfall of any rate class group. Flex customer revenues amount only to about $4.3 million, whereas costs allocated to that customer group are $38.2 million at proposed rates.

However, as we explained earlier, the Company claims that the current rate revenues represent the maximum amount that can be earned from these customers. Thus, the $34 million shortfall from this class must be recovered from the other rate classes.

To provide useful cost allocation results for revenue allocation, we reallocated this shortfall to the other rate classes. Because the costs allocated to the flex rate customers are dominated by mains plant, it can reasonably be inferred that the unrecovered costs are mains-related.[23] We therefore reallocated the flex rate shortfall to the other rate classes using the P&A mains allocation factor.

[22] At this writing, an interrogatory is outstanding relating to the meters allocation factor. We will update our analysis should any resulting findings prove to have a material impact.

[23] Mains represent over 90 percent of the utility plant assigned to the flex rate customer group. See IEc WP2.

Q. What are the implications of your alternative ACOSS analysis?

A. Table IEc-3 shows class rates of return at current rates under the Company's approach and IEc's alternatives.

Table IEc-3
Comparison of ACOSS Results
Class Rate of Return at Current Rates

	Columbia	**IEc Alternative**	**IEc Alternative with Flex Adj.**
Residential	8.0%	7.7%	6.6%
SGS1	6.7%	7.2%	5.9%
SGS2	6.7%	6.6%	5.1%
Med Gen'l (SDS/LGSS)	5.4%	5.2%	3.6%
Lg Gen'l (LDS/LGSS)	1.7%	1.5%	-0.1%
MDS	179.2%	179.2%	178.6%
Flex	-4.2%	-4.0%	NM
Total*	**6.1%**	**6.1%**	**5.6%**

* Total return excludes flex class in column 3.
Source: IEc WP2, IEc WP3

Table IEc-3 indicates that only modest changes result from our modifications to the Company's ACOSS. The general patterns are the same. The Residential class is modestly over-recovering costs, the Small and Medium general service classes moderately under-recover costs, and the Large general service class substantially under-recovers allocated cost.[24] In particular, we note that the revenues from the Large General (Rate LDS/LGSS) customer class represent less than half the class's allocated costs. Thus, to move revenues in line with costs for that class, a rate increase of more than 100 percent would be necessary.

[24] As we indicated earlier, the MDS class consists of large customers located in close proximity to interstate pipelines, and mains costs are directly assigned to these customers. These customers have historically provided a cross-subsidy to the other classes, generally because rate decreases have not been applied to reduce rates to allocated costs. The Company proposes to continue this practice in this proceeding, by assigning a zero increase to the class.

5. Revenue Allocation

Q. What is revenue allocation?

A. Revenue allocation is the assignment of the dollar net increase or decrease to each of the Company's rate classes in a base rates proceeding. In contrast, *rate design* determines how the allocated revenue is recovered from individual ratepayers within each class. From a cost recovery standpoint, revenue allocation addresses *inter-class* cross-subsidization issues, while rate design addresses *intra-class* cross-subsidization issues.

Q. What are the primary economic and regulatory criteria for revenue allocation?

A. In general, allocated cost is the primary criterion used by regulators in the revenue allocation process. Most utilities and regulators adopt a policy in a base rates proceeding of attempting to move revenues more into line with allocated costs by varying the magnitude of the rate increases for the individual classes. However, regulators also subject the rate increases to other non-cost criteria of ratemaking. Of the traditional rate design criteria, the most common non-cost considerations in the revenue allocation process are:

- the *gradualism* principle (or avoidance of "rate shock"), in which large rate increases for individual customers or classes of customers are avoided; and

- the *value of service* principle, which is often used to mitigate rate increases for customers or customer classes with relatively elastic demand. [25]

Using these criteria, the utility will develop a proposal for assigning the increase in the revenue requirement among the classes that reflects both cost and non-cost considerations. With this proposal, the ACOSS can be simulated at both present and proposed rates to evaluate the magnitude of "progress" that has been made toward the policy of achieving cost-based rates.

[25] See, for example, Principles of Public Utility Rates, Second Edition, Bonbright, Danielsen, Kamerschen, 1988, pages 383 to 387. The criteria in this text apply to the overall development of a utility rate structure. The criteria that we discuss in this testimony are those that apply to the revenue allocation portion of the process, which is only one aspect of the overall development of utility rates.

Q. Please summarize the process used by Columbia for its proposed revenue allocation in this proceeding.

A. Witness Johnson reviews the Company's considerations at pages 16-19 of Statement No. 6. In short, the Company's criteria appear to be that the revenue allocation produce rates that are just and reasonable, not unduly discriminatory, and which move each class cost recovery closer to "parity." Cost recovery is evaluated using the indexed rate of return metric at current and proposed rates, with the goal of moving each class's value closer to unity.[26] Witness Johnson also cites to the principle of "rate gradualism," and sets a limit that no rate increases be more than 1.5 times the system average. Finally, Witness Johnson indicates that only minimal increases can apply to the flex rate customers, because rates for those customers are set based on competitive circumstances rather than cost of service.

Armed with those criteria, the Company proposes to set the rate increases for the MDS and Flex classes near zero, the rate increases for the SDS/LGSS and LDS/LGSS classes near the 1.5 times system average (20-22%), and the increases for the Residential and SGS1/SGS2 classes about at system average (13.5-14.5%).

Q. Please comment on the Company's use of the indexed rate of return metric for evaluating progress toward cost-based rates.

A. The indexed rate of return metric is derived as the ratio of the class rate of return on rate base to the systemwide average return on rate base. Thus, for example, if a rate class is earning 2 percent on rate base at current rates and the system average is 5 percent, the indexed rate of return metric is 2.0/5.0 = 0.4. The metric (correctly) indicates that this class is under-recovering costs.

Unfortunately, the indexed rate of return is not a reliable measure of progress toward cost-based rates when it is evaluated at current and proposed rates. The indexed rate of return metric can, in some circumstances, imply that a particular revenue allocation proposal will result in progress toward cost-based rates when in fact revenues are moving farther away from allocated costs. Moreover, even when the indexed rate of return correctly indicates

[26] The Company refers to the metric as the "unitized rate of return." It is also often called the "relative rate of return" metric.

that progress is occurring, it will overstate the relative magnitude of that progress. Our reasoning for this conclusion is detailed in Appendix A to this testimony.

We also recognize that the Commission has recently supported the use of the dollar subsidy metric for evaluating progress toward cost-based rates, where the dollar difference between a class's revenues and allocated costs is compared at current and proposed rates.[27] This metric is also evaluated in Appendix A. As shown, this metric is not nearly as flawed as the indexed rate of return metric, in that it will not mistakenly report progress when there is none. However, this method can potentially imply that no progress toward cost-based rates is occurring for a revenue allocation proposal when in fact some modest progress is achieved.

For this proceeding, we relied on the normalized revenue-cost ("R-C") ratio metric. The "R-C" metric represents (unsurprisingly) the ratio of class revenues to class allocated costs, and thus implicitly recognizes the subsidy as a percentage of the class revenue requirement. As detailed in Appendix A, this method relies entirely on the full test year cost claim as a measure of cost to avoid the distortions associated with excluding some return on capital costs in its evaluation of current revenue-cost performance. As shown in Appendix A, this method does not suffer from the common biases of the other metrics.

Q. How does the Company's revenue allocation proposal stack up using the normalized revenue-cost ratio metric?

A. We conclude that the Company's proposal generally makes a small amount of progress toward cost-based rates for all classes except the Flex customer class, once the severe shortfall from the Flex rate class is reallocated. We evaluate the Company's proposal using the Company's ACOSS, modified only to reallocate the Flex class shortfall, as shown in IEc WP2. Table IEc-4 below provides a summary of our evaluation of the Company's revenue allocation proposal, using the Company's ACOSS.

[27] *Pennsylvania Public Utility Commission v. City of Bethlehem -- Water Department*, Docket No. R-2020-3020256, Order entered April 15, 2021, at 36.

Table IEc-4 Summary of Columbia Revenue Allocation Proposal					
	Increase $mm	Increase %	R/C Current	R/C Proposed	"Progress"
Residential	$56.39	13.4%	107.5%	107.0%	7.3%
SGS1	$ 6.92	14.4%	95.8%	96.1%	7.5%
SGS2	$ 7.33	14.6%	93.4%	93.9%	7.8%
Med Gen'l (SDS/LGSS)	$ 6.16	20.5%	83.3%	88.0%	28.3%
Lg Gen'l (LDS/LGSS)	$ 5.25	22.0%	55.0%	58.8%	8.5%
MDS	--	0.0%	1349.8%	1184.1%	13.3%
Flex	$ 0.01	0.3%	NM	NM	NM
Total	**$82.06**	**14.2%**	**100.0%**	**100.0%**	--

Flex rate cost performance is not meaningful because the shortfall is reallocated to other rate classes. Columbia's filed ACOSS implies a shortfall of $41 million, but that values is overstated due to an acknowledged error.

Source: IEc WP2

As shown in Table IEc-4, because the Company's revenue allocation shows very little difference among the Residential, SGS1 and SGS2 classes, none of those classes makes any material progress toward cost-based rates. Moreover, because the revenue-cost ratio for the LDS/LGSS class is so low, an increase even at 1.5 times the system average results in little progress toward cost-based rates. The only classes to exhibit even moderate progress toward cost-based rates are the Medium General (SDS/LGSS) class (with an increase well above system average) and the MDS class (with no increase). Our analysis of this proposal indicates that the Company's inability to make material progress toward cost-based rates primarily lies with the gradualism constraints for the LDS/LGSS rate class.

Q. What is your alternative revenue allocation proposal?

A. We developed an alternative revenue allocation proposal that (a) relies on our alternative ACOSS, (b) is somewhat more aggressive in attempting to move rates into line with allocated cost for the smaller customer classes, and (c) allows for a larger rate increase for the LDS/LGSS class to reflect the enormous revenue-cost difference under current rates.

Regarding the last consideration, a common rule of thumb for rate gradualism is to limit the increase for any particular rate class to no more than 1.5 or 2.0 times system average. Under normal conditions, the 1.5 times parameter will not unduly constrain the ability of the regulator to move rates substantially more into line with allocated cost. However, as shown in the Company's revenue allocation, the 1.5-times limit in this case produces little in the way of progress toward cost-based rates for the LDS/LGSS class. Thus, for the purposes of this proceeding, we assign the LDS/LGSS class an increase at the upper end of the range, or 2.0 times system average. This adjustment produces some modest progress toward cost-based rates, with the revenue-cost ratio moving from 54.6% under current rates to 61.4% under proposed rates.

For the other two classes that under-recover costs at present rates, we assign rate increases that result in moving the revenue-cost ratio 30 percent of the way toward unity, resulting in increases of 16.2 percent for the SGS2 class and 21.1 percent (about 1.5 times system average) for the SDS/LGSS class.

For the Residential and SGS1, we calculate a rate increase that results in equal progress toward cost-based rates using the normalized revenue-cost ratio metric.

Finally, we accept the Company's proposal for the MDS and Flex rate classes for *de minimis* rate increases.

The results of our alternative revenue allocation proposal are summarized in Table IEc-5 below and provided in detail in IEc WP3. As shown, our proposal results in more progress toward cost-based rates than the proposal put forward by the Company, although the progress remains relatively modest even with the relaxed constraints on increases for the larger customer classes. Our proposal for the small to medium commercial classes results in a slightly smaller increase for SGS1 than that proposed by the Company, and a modestly larger increase for the SGS2 class.

Table IEc-5 Summary of IEc Alternative Revenue Allocation Proposal					
	Increase $mm	Increase %	R/C Current	R/C Proposed	"Progress"
Residential	$54.05	12.9%	106.8%	105.5%	18%
SGS1	$ 6.75	14.0%	100.8%	100.6%	18%
SGS2	$ 8.10	16.2%	94.5%	95.5%	30%
Med Gen'l (SDS/LGSS)	$ 6.35	21.1%	83.2%	88.3%	30%
Lg Gen's (LDS/LGSS)	$ 6.78	28.4%	54.6%	61.4%	15%
MDS	--	0.0%	1332.9%	1167.3%	13%
Flex	$ 0.01	0.3%	NM	NM	NM
Total	**$82.06**	**14.2%**	**100.0%**	**100.0%**	--

Flex rate cost performance is not meaningful because $40 million shortfall is reallocated to other rate classes.

Source: IEc WP3

6. <u>Rate Design Issues</u>

Q. Please describe the tariff structure for the SGSS, SCD and SGDS rate classes.

A. Base rate tariff charges for these three classes currently consist of a bifurcated monthly customer charge and a bifurcated commodity charge, both split between customers with annual consumption above and below 644 Dth. Within each size category, SGSS and SCD customers pay the same commodity charge, while SGDS customers pay a slightly lower commodity charge reflecting the fact that the Company does not incur gas storage working capital costs for regular transportation customers. The basic distribution rate tariff structure is shown in Table IEc-6 below.

In addition, the SGSS sales customers are subject to PGC, GPC, MFC and Rider CC charges. Rate SCD Choice and Rate SGDS transportation customers are subject to certain PGC charges (related to load balancing), and the Rider CC charge.

Q. How does Columbia propose to implement its rate increase for these classes?

A. Columbia's proposed increases for the base rates components of Small General Service classes are shown in Table IEc-6 below.[28] The Company has essentially proposed to assign class-average increases to both the customer charge and the commodity charge for each class. In effect, the Company proposes no change to rate design for these classes.

Table IEc-6
Columbia Proposed Small General Service Base Rate Design

	Current Rate	Proposed Rate	Percent Increase
Rates SGSS and SCD			
Customer Charge < 644Dth/year	$29.92	$34.23	14.4%
>644 Dth/year	$57.00	$65.36	14.7%
Commodity Charge <644 Dth/year	$6.2048	$7.0989	14.4%
>644 Dth/year	$5.2647	$6.0374	14.7%
Rate SGDS			
Customer Charge < 644Dth/year	$29.92	$34.23	14.4%
>644 Dth/year	$57.00	$65.36	14.7%
Commodity Charge <644 Dth/year	$6.1199	$6.9998	14.4%
>644 Dth/year	$5.1797	$5.9382	14.6%

Q. What approach do you recommend for setting rates for these classes?

A. For small and medium general service classes, we generally advocate setting the customer charge at or modestly below the customer-related costs for the smaller customers within each class, subject to rate gradualism constraints. Columbia Gas appears to agree with this approach. Witness Johnson indicates, *"In essence, customer-related costs that bear no relationship to customer gas consumption patterns should be recovered through the fixed*

[28] Table Iec-6 shows the Company's proposed rate design as detailed in Exhibit 103 Schedule 7, which appears to be consistent with the proposed revenues reported in the Company's ACOSSs. These values do not appear to be consistent with the testimony of Columbia witness Melissa J. Bell (Statement No. 3) at pages 36-37.

portion of the rate design, i.e. the monthly customer charge."[29] The commodity charge is then adjusted to produce the appropriate revenue requirement.

The Commission's decision regarding the appropriate cost allocation methodology has an impact on the cost basis for the customer charge, particularly for the non-residential rate classes. In the past, when some portion of mains were seen as having a customer component to costs, it was reasonable to include those costs in the derivation of the cost basis for non-residential customer charges. In the P&A ACOSS method, no mains costs are classified as customer-related, which reduces the cost basis for the customer charge. As detailed below, this cost allocation change constrains the magnitude of the customer charge increase for some non-residential rate classes. While Columbia may continue to believe that mains have a customer cost component for rate design purposes, the Commission does not.

Q. How do you determine the cost basis for the customer charge?

A. We begin with our replicated version of the Company's P&A ACOSS model, which separately tracks customer-related costs. In developing the cost basis for the customer charge, we take a relatively simple approach to the problem, in that we include all costs that are allocated on a customer basis in the ACOSS model. We recognize that some experts, and at least some Commission precedent, support the exclusion of certain "indirect" customer-related costs from this calculation, particularly for residential customers. Nevertheless, we follow the basic principle that the rates should follow the costs. If customer charges are set below the allocated customer cost, then larger customers will subsidize smaller customers, as measured by the logic of the ACOSS. While subsidizing smaller customers may have a public policy rationale for the residential class, we see no particular advantage to such an intra-class cross-subsidy for the non-residential classes.

This analysis is detailed in IEc WP3, in the "Customer" worksheet.

Q. What are the implications of your analysis for the SGS/SGDS customer class customer charges?

[29] Columbia Statement No. 6 at 22.

A. As detailed in IEc WP2, our customer cost analysis shows that the SGS1 customer cost is approximately $36, which is slightly above the Company's proposed increase to $34.23. As a check, we compared the Company's proposed charge with those of other Pennsylvania NGDCs in Table IEc-7 below. That review demonstrates that Columbia's proposed customer charge would be among the highest in Pennsylvania, but that is unsurprising since Columbia has the highest distribution rates in the Commonwealth.

Table IEc-7 Non-Residential Customer Charges: Pennsylvania NGDCs	
	$/month
National Fuel Gas Dist'n C&PA (< 250 mcf)	$19.89
Peoples Natural Gas SGS (< 500 mcf)	$20.00
UGI Gas N/NT	$23.50
PGW GS-C	$25.35
PECO Gas GC	$28.55
Columbia Gas SGSS/SCD/SGDS (Current)	**$29.92**
UGI Gas N/NT (Proposed)	$30.00
Columbia Gas SGSS/SCD/SGDS (Proposed)	**$34.23**
PECO Gas GC (Proposed)	$38.82
Peoples Gas (TWP) SGS (<500 mcf)	$35.00
Sources: IEc WP1 "Rate Comp" worksheet.	

Based on this review, we conclude that the Company's proposed increase to the SGS1 customer charge is not unreasonable. However, because the proposed increase is close to the fully allocated customer cost at the full revenue requirement, if the Company's overall rate increase is scaled back, so too should the increase to the SGS1 customer charge.

For the SGS2 customers, however, our analysis shows a customer cost of $53.59, which is *below* the *current* customer charge of $57.00, and far below the Company's proposed $65.36 charge. Based on the cost analysis, we therefore recommend that no increase be applied to the SGS2 customer charge in this proceeding. Any increase to the SGS2 class should be recovered in the volumetric charges.

6. Rate Decoupling/Revenue Normalization Adjustment

Q. Do you have any comments on any other aspects of Columbia's filing?

A. Yes. Columbia's filing includes a proposal for the implementation of a Revenue Normalization Adjustment ("RNA") mechanism for residential customers except those who participate in the Consumer Assistance Program ("CAP").

Q. What is the RNA mechanism?

A. Columbia's proposed RNA mechanism is a form of a rate "decoupling," that utilities use to "weaken" or "break" the link between revenues and customer gas consumption. Decoupling mechanisms allow utilities to adjust rates and/or implement charges and credits to customer bills to ensure the utility receives a pre-established, benchmark level of revenue.

Q. What is the apparent allure of RNA and other decoupling mechanisms and what are the drawbacks?

A. From the utility's perspective, an RNA mechanism such as the one Columbia proposes theoretically provides the utility with financial certainty against changes to gas consumption that would otherwise cause variability in the utility's revenue. Tying billing to revenue benchmarks removes the effect of variabilities in consumption levels outside of the utility's control. In short, the RNA mechanism reduces utility risk. Certain types of rate decoupling mechanisms may potentially reduce the frequency of rate cases, where revenues targets are adjusted annually by formula rather than by rate case. However, in this case, Columbia's proposed RNA mechanism effectively adjusts the rate for the non-CAP residential class on a period-by-period and year-by-year basis outside of the framework of rate case filings. Residential customers will consistently have their rates adjusted to account for revenue shortfalls or surpluses without the transparency and due diligence that accompany rate cases.[30] Further, because the RNA mechanism only applies to the residential class, future rate cases would still be required at the same frequency as before to capture cost and revenue allocation adjustments beyond the residential class.

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[30] While the revenue reconciliation will be subject to a Commission proceeding, such additional proceedings will simply add to the already significant oversight burden placed upon Commission staff and intervenor groups.

From the customers' perspective, decoupling mechanisms may lower the barrier to energy efficiency programs by insulating utilities from their accompanying decrease in consumption. It is therefore presumably not a coincidence that Columbia is proposing to implement a Three-Year Energy Efficiency Plan for residential customers simultaneous with the proposed adoption of the RNA mechanism. Decoupling mechanisms also potentially allow customers to recover payments in excess of the utility revenue benchmarks following periods of higher-than-expected consumption. Of course, the latter benefit flows in both directions, because decoupling permits utilities to issue charges to recoup missed revenue below benchmarks following periods of lower-than-expected consumption.

Decoupling mechanisms come with several other drawbacks for customers. The decoupling adjustment may be complicated and difficult for customers to understand and evaluate. Decoupling shifts financial risks associated with gas consumption variability from the utility, which experienced those risks as fluctuating revenue, to the customer, who will now assume those risks in the form of rate adjustments to normalize revenue. Finally, decoupling disincentivizes the utility from investing resources into reliability, because the utility's revenues are no longer tied to its deliveries.[31]

Q. Why are you addressing this proposal when it applies only to the residential class?

A. If approved for the residential class, the Company will almost certainly rely on the precedent to support extending the mechanism to other rate classes, particularly the small commercial classes.

Q. Please summarize the Company's proposed Revenue Normalization Adjustment mechanism.

A. Under the proposed RNA mechanism, Columbia would establish a benchmark distribution revenue per non-CAP residential customer bill ("BRDB") for peak (October through March,

[31] Substantial literature is available regarding rate decoupling mechanisms and their relative advantages and disadvantages. In preparing this testimony, we found the following resource to be helpful and incorporate a number of its insights in this text: Christina Simeone, "Rate Decoupling: Economic and Design Considerations," April 29, 2016, Kleinman Center for Energy Policy." Accessed at: https://ipu.msu.edu/wp-content/uploads/2017/09/Rate-Decoupling-Simeone-2016.pdf

"BDRBp") and non-peak (April through September, "BDRBo") periods.[32] In its filings, Columbia calculates its BDRBp (i.e., the total revenue per non-CAP residential bill that Columbia expects to receive for a given six-month period from October through March) to be $715.62 and its BDRBo (i.e., the total revenue per bill that Columbia expects to receive from April through September) to be $314.92. Beginning with an abbreviated three-month peak period starting in January 2023, Columbia would then compare the BDRB for a given peak or off-peak period and compare it with Columbia's actual distribution revenue per non-CAP residential customer bill ("ADRB," "ADRBp," "ADRBo") in that period. The Company would then take the difference between the BDRB and ADRB, multiply the difference by the total number of bills for that period, and divide the total surplus or shortfall in revenue versus expected benchmark revenue by the number of therms forecast to be distributed in the *following* peak or off-peak period (i.e., the shortfall or surplus for the period April 2023 through October 2023 would be divided by the forecast therms for the period April 2024 through October 2024, the next off-peak period).

The shortfall or surplus per forecast therm is the RNA and would be applied to non-CAP residential customers' bills as a per therm charge or credit in the forecast period. Through these charges or credits, Columbia would collect from or return to the non-CAP residential customers the shortfall or surplus, respectively, its revenues experienced in the previous peak or off-peak period. RNA charges and credits on customers' bills would include interest at the commercial prime rate. Conceptually, Columbia applies interest because the charges and credits reflect revenue the Company *should* (for charges) or *should not* (for credits) have received in the previous period.

Effectively, the RNA would change the rates that non-CAP residential customers pay on a period-by-period and year-by-year basis, based on whether Columbia experienced a revenue shortfall or surplus from the class in the previous peak or off-peak period.

Q. You indicate that the RNA would provide revenue stability for Columbia through a guaranteed recovery of revenue per customer. Is the RNA similar to Columbia's

[32] The RNA proposal is discussed in Columbia Statement No. 6 beginning at 29.

weather normalization adjustment ("WNA") mechanism that is currently in place for providing bill stability for ratepayers?

A. No, it is not. The WNA and RNA mechanisms have two substantial differences. First, the WNA is a "real time" mechanism, in that the weather effects of a particular month are reflected in the bill to the customer for that month. Thus, in an unusually cold month, the customer is billed at an average effective rate that is lower than normal. This mechanism provides some real-time bill stability for customers. (Customers, of course, must continue to fully absorb weather risk in their purchased gas costs.) In contrast, the RNA is a longer-term reconciliation mechanism, in which revenue variances in one season are deferred for recovery to the next season. This deferral provides revenue stability for the utility because the deferred amount is recognized as a regulatory asset/liability. However, the deferral provides no bill stabilization benefit to ratepayers, and may in fact increase variability from year to year.

Second, adjusting current distribution bills for weather variability arguably provides revenue/bill stability to both utility and ratepayer. Since weather variability is absorbed in the WNA, one of the largest causes for revenue variances that will be absorbed in the RNA will be overall economic conditions. For these variances, the RNA will compound the economic risk to ratepayers, while substantially reducing the risk to shareholders. This would be particularly problematic for small business customers, were the RNA to be expanded to non-residential customers. For example, during an economic downturn, small businesses face reduced demand for their products and services, and thus lower revenues and less ability to reinvest in their businesses. Columbia's proposed RNA would compound the negative impact of the economic downturn by an after-the-fact tax on those small businesses, all in the name of eliminating economic risk to Columbia's shareholders.

Q. Has Columbia accounted for customer drawbacks of decoupling in its implementation of its proposed RNA mechanism?

A. No. Under its proposed RNA mechanism, Columbia stands to benefit from whatever increased financial certainty the mechanism will provide and the ability to adjust residential rates outside of rate cases without establishing corresponding and equal benefits to residential customers. Further, the RNA shifts the risk of variable gas consumption from the

Company to the customer without any reduction in the Company's rate of return to compensate residential customers for the benefits that will accrue to Columbia.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX A

MEASURES OF PROGRESS TOWARD COST BASED RATES

PENNSYLVANIA UTILITY COST AND REVENUE ALLOCATION

Introduction

The Pennsylvania Commonwealth Court held that cost of service is "the polestar" criterion for assigning a utility rate increase among the various rate classes.[33] Parties to Pennsylvania base rates proceedings generally agree that this criterion implies that the revenues for each class at the rates approved by the Commission should be closer to allocated costs than the rates in place when the rate case is filed. Thus, parties to the proceeding will typically compare some metric for cost recovery under "proposed rates" with that same metric for cost recovery under "current rates." This comparison can show (a) *whether* the proposed rates result in class revenues that are closer to allocated costs, and (b) *how much* progress the proposed rates make toward moving class revenues toward allocated costs.

While different metrics are used for this analysis, the most common metric in Pennsylvania is the "indexed rate of return" metric (also called the "relative rate of return" or "unitized rate of return" metric). This appendix demonstrates why the indexed rate of return is not a reliable metric for identifying whether proposed rates are closer to allocate costs than current rates, and that even where the indexed rate of return correctly implies that there is progress toward cost-based rates, it is not a reliable indicator of the amount of progress that is achieved.[34] This appendix also compares the indexed rate of return to three other metrics for evaluating progress toward cost-based rates, namely the dollar subsidy, the rate of return differential, and revenue-cost ratio metrics.

[33] Lloyd v. Pennsylvania Public Utility Commission, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006).

[34] This problem with the indexed rate of return metric was identified in OSBA-sponsored testimony at least as early as 1994. This critique has been presented in expert testimony many times since. No credible rebuttal to these basic conclusions has been submitted, but the widespread use of this flawed metric continues.

The Structure of the Cost Allocation Study

The indexed rate of return metric is derived from the method that is most often used for utility cost allocation in Pennsylvania. When a utility or regulator develops a revenue requirement for a test year, it simply sums all of the individual cost items for that year, including operating and maintenance ("O&M"), administrative and general ("A&G"), depreciation, taxes other than income, income taxes and allowed return on rate base. Thus, the objective of a cost allocation study should be to simply allocate each of these cost elements to the various rate classes. Because the allowed return and associated income tax are derived from rate base, the cost allocation study allocates all net plant and other rate base items to the various rate classes, and the return and income taxes can then be allocated in proportion to rate base.

Cost allocation studies in Pennsylvania, however, are most often conducted on a class rate of return basis. That is, the cost allocation study calculates a class rate of return by taking revenues, deducting the allocated O&M, A&G, depreciation and taxes other than income, to produce a pre-tax class net income. Income taxes are then most often allocated based on the calculated pre-tax class income, and a net income by class value is derived by difference. The allocated pre-tax and net income figures are thus not a cost of capital, but represent the implied return provided by each class under the revenues (current or proposed) used in the cost allocation study. These net income values are then divided by the allocated rate base, to produce percentage class rates of return.[35] Thus, with this approach to cost allocation, there is a desire by utilities and regulators to develop a metric for evaluating progress toward cost-based rates that is based on the class rates of return produced by the cost allocation study.

Defining Progress Toward Cost-Based Rates

It is not necessarily obvious what it means to "move rates more into line with allocated cost" between current and proposed rates. At the simplest level, one could argue that if the current rate revenues for a particular class are below the allocated cost for that class at the full proposed

[35] Some Pennsylvania utilities also calculate cost of service using a "levelized rate of return" method, in which return and income tax costs are allocated such that each class produces the system average rate of return. This approach is arithmetically equivalent to allocating return and income tax costs in proportion to rate base, as described above.

revenue requirement, any increase in rates will move that class's revenues closer to allocated cost. However, the objective of this exercise is to measure the progress toward cost-based rates for each rate class compared to that for all of the other classes. Thus, a revenue allocation proposal must be evaluated for its impact on all of the rate classes.

Also at the simplest level, of course, a proposed revenue allocation will by definition move rates more into line with allocated cost if each class's revenues are moved exactly to the full proposed allocated cost of service. Or, equivalently, rates are exactly cost-based when each class's revenues are set such that the class produces the system average rate of return. Therefore, there is no question that moving a class exactly to an indexed rate of return of unity (1.0) is necessarily consistent with making rates more cost-based.

In many base rate proceedings, however, moving rates fully into line with allocated costs cannot be achieved due to consideration of other rate design factors, most notably "rate gradualism," which serves to limit the increase for any particular class of customers in any rate proceeding, and has the aim of gradually moving rates into line with allocated cost.

Thus, in terms of determining whether a particular rate proposal moves rates into line with allocated cost, this appendix takes the position that there is progress toward cost-based rates if the proposed relative rate increases across the various classes, when followed for a number of base rates proceedings (in which there is no change in the relative cost structure), will eventually result in cost-based rates. Thus, for any particular metric, it is important to consider not only the difference between the metric and current rates and proposed rates in one base rates case, but also what that metric will imply going into the next base rates case.

As shown further in the numerical example below, this standard for defining progress implies that for classes with revenues below allocated cost at current rates (or, equivalently, with a class rate of return below system average), progress can only be achieved by assigning that class a rate increase above the system average increase. This, of course, is just plain common sense. If a class is under-recovering costs, it should be assigned an above average increase. As shown below, however, the indexed rate of return metric fails at common sense.

The Numerical Example

This appendix takes the approach of defining a specific numerical example, and showing the implications of various different metrics on different rate increase scenario. The calculations associated with this example are also provided in MS Excel electronic format (IEc WP5), and parties are able to simulate alternative examples to evaluate the rigor of this analysis.

The example attached to this appendix shows the arithmetic impacts of a single two-class utility example under four different rate increase proposals. Each page shows the implications of a different revenue-cost metric, namely the indexed rate of return, dollar subsidy, differential rate of return, the revenue-cost ratio and the normalized revenue-cost ratio.

The example involves two rate classes, A and B, in which each generates the same revenue at current rates, but in which Class A has a moderately higher cost to serve. The four rate increase scenarios are (I) an across-the-board increase in which both classes get the same percentage increase, (II) a scenario with a moderately higher percentage increase for Class B, and (III) a slightly higher percentage increase for Class A, and (IV) a moderately higher percentage increase for Class B.

The common-sense answer is that the across-the-board scenario (I) should show no progress toward cost-based rates, Scenario II should indicate that revenues are moving farther away from costs, and Scenarios III and IV should show that revenues are moving slightly and modestly closer to allocated costs. The discussion of each metric below highlights where the metric produces results that are at odds with these expectations.

To evaluate the question as to whether there is consistent progress toward cost-based rates, the metrics are evaluated at both proposed rates in the "current" base rates proceeding, and for what the values would imply going into the next base rates case after a uniform increase in costs.

The Indexed Rate of Return Metric

The indexed rate of return metric is measured as the class rate of return divided by the system average rate of return, at current and proposed rates. If revenues are fully in line with allocated costs, the class indexed rate of return is unity (1.0). Thus, if a class has an indexed rate of return at present rates that is higher than system average, it is deemed to be over-recovering costs, and conversely, where the indexed rate of is below unity, the class is under-recovering allocated costs.

As a standalone measure for relative cost performance, there is nothing wrong with the indexed rate of return metric – for any particular system average rate of return scenario, the farther a class's indexed rate of return is from unity, the farther it is from allocated costs.

Moreover, since an indexed rate of return of unity represents cost-based rates, it is conceptually appealing to conclude that if the indexed rate of return moves closer to unity, there is progress toward cost-based rates. Moreover, it is similarly appealing to conclude that progress toward cost-based rates could be measured by how much closer the index gets toward unity between current and proposed rates. Unfortunately, this intuitive approach fails in the actual arithmetic.

Utilities have used this argument for decades in Pennsylvania. While it is not clear why alternative methods have not been adopted, it may be that the metric is attractive to both utilities and regulators in that it tends to show significant progress toward cost-based rates when in fact there is little such progress. This then allows utilities to claim that they are following the cost standard without having to make politically unpopular decisions regarding differentiating rate increases among the various rate classes.

When applied in an actual example, the indexed rate of return fails even the simplest test. In the example shown, the current rates class rates of return are 2.50% and 5.71% for Classes A and B respectively, producing indexed rates of return of 0.625 and 1.429 relative to the system average return of 4.00%. When a 30% increase is applied to both classes, the system average rate of return rises to 8.00%, and the class returns rise to 6.25% and 10.00% respectively, yielding indexed rates of return of 0.781 and 1.250.

Thus, despite the fact that both classes get the same percentage increase and common sense says that there should be no progress toward cost-based rates, the indexed rate of return metric not only implies that there is progress, but that there is significant progress. The Class A indexed rate of return moves from 0.625 to 0.781, which appears to imply that the class has moved 42 percent of the way to cost-based rates.[36]

The fallacy of this logic is shown in the implications for the next rate case. When costs increase, the system average rate of return falls back to its lower level and the indexed rate of return metrics all shift farther away from unity. Thus, as shown, an across-the-board increase in the current rate case followed by an across-the-board cost increase for the next case will demonstrate that, in fact, there is no progress toward cost-based rates and the indexed rates of return are right back where they started.

The other revenue increase scenarios show similar problems with the indexed rate of return metric. In Scenario II, despite a smaller percentage increase for the higher-cost Class A, the indexed rate of return again implies that there is progress toward cost-based rates, which is obviously nonsense. This is again demonstrated by the implications for the next base rates case, which understandably show that rates are farther out of line than they were going into the current rate case. It is simply unreasonable to believe that assigning larger percentage increases to the rate class that is already over-recovering costs will somehow reduce inter-class subsidies. And yet that is the implication of the indexed rate of return metric.

In Scenarios III and IV, the indexed rate of return does produce the correct directional answer, namely that rates are moving more into line with allocated cost. But the indexed rate of return metric implies that both scenarios result in enormous progress toward cost-based rates, when in fact there is relatively little progress, particularly in Scenario III. As shown in the example, despite a small differential in the rate increases, the indexed rate of return implies that revenues have moved 50 percent of the way toward allocated cost. Realistically, however, as shown in the implications for the next base rates case, the actual progress is much lower.

Thus, the indexed rate of return metric is a wholly unreliable guide for evaluating progress toward cost-based rates in a utility rate proceeding, because it (a) may show progress toward cost-

[36] "Progress" is measured by how much the metric has moved divided by how far it needs to move to become fully cost-based. Thus, in the residential class example, the index moves from 0.625 to 0.781, a difference of 0.156, compared to moving fully to cost-based rates, which would require the index to move from 0.625 to 1.000, a difference of 0.375. Progress is measured as 0.156/0.375, or 42 percent.

based rates when in fact revenues are moving farther away from costs, and (b) will overstate the magnitude of progress toward cost-based rates when progress is occurring.

<u>The Dollar Subsidy Method</u>

While the indexed rate of return metric is the most common approach used by Pennsylvania utilities, the Commission has also supported the use of the dollar subsidy metric. In an order involving the City of Bethlehem – Water Department, the Commission concluded:

> "As noted by the OSBA, the proper yardstick for measuring the degree of movement toward cost of service is the change in the absolute level of class subsidies at present and proposed rates."[37]

In the dollar subsidy method, the total cost to provide service is calculated using the method described above, in which each component to cost, including return and income taxes, is allocated to each cost. The difference between current rate revenues and the allocated cost is the dollar subsidy.[38]

In allocating the return and income tax costs under the "current rates" evaluation, the values used represent only the return that the utility would achieve and the income taxes that it would incur if it were assigned no rate increase. These values therefore do not represent the utility cost of capital, but simply residual values of what is left from current rate revenues after O&M, A&G, depreciation and other taxes are deducted.

When the dollar subsidy metric is applied to the four alternative revenue allocation proposals in the attached example, it implies the following:

- For the across-the-board increase, the dollar subsidy metric indicates that the dollar value of the revenue-cost difference increases under proposed rates, implying that rates

[37] *Pennsylvania Public Utility Commission v. City of Bethlehem -- Water Department*, Docket No. R-2020-3020256, Order entered April 15, 2021, at 36.

[38] This appendix uses the term "subsidy" as the difference between revenues and fully allocated cost in a utility cost allocation study. Theoretical economics generally defines subsidy based on incremental cost concepts, rather than fully allocated cost.

are moving farther away from costs. In dollar terms, that conclusion is correct, although in percentage terms the subsidies remain the same.

- When a larger increase is assigned to Class B, the dollar subsidy metric indicates correctly that rates are moving farther away from allocated cost, and that the problem will be worse with the next base rates proceeding.

- When a modestly larger increase is assigned to Class A, the dollar subsidy metric implies that there is no progress toward cost-based rates in the current rate proceeding, and that the situation will be worse in the next base rates case. In effect, even though the slightly higher rate increase for Class A will (eventually) lead to cost-based rates, the dollar subsidy method implies that there is no progress.

- When a materially larger increase is assigned to Class A, the dollar subsidy metric correctly indicates that there is progress toward cost-based rates.

Thus, overall, the dollar subsidy metric will tend to slightly understate progress toward cost-based rates, but the distortion is far smaller (and in the opposite direction) of that of the indexed rate of return metric.

The Differential Rate of Return

The differential rate of return metric is similar to the indexed rate of return metric, in that both approaches calculate class rates of return and current and proposed rates, and compares each class's return to the system average. However, where the indexed rate of calculates the *ratio* of class to average return, the differential rate of return calculates the *difference* between class and average rates of return. In the indexed rate of return, cost-based rates are achieved with an indexed rate of return of unity (1.0); for the differential rate of return, cost-based rates are achieved with a differential rate of return of zero.

When applied to the four revenue allocation scenarios in the example, the differential rate of return produces results that are nearly the same as the dollar subsidy method. That is, the differential rate of return calculation will slightly understate progress toward cost-based rates, but the results are much less distorted than those from the indexed rate of return metric.

Revenue-Cost Ratio

The revenue cost ratio is similar to the dollar subsidy metric, except rather than taking the difference between revenues and allocated costs, it takes the ratio of revenues to allocated cost. Like the indexed rate of return, cost-based rates are achieved at a revenue-cost ratio of unity (1.0 or 100 percent).

Unlike the indexed rate of return metric, however, the revenue-cost ratio generally does not distort the implications of a revenue allocation proposal. As shown in the example, in all four revenue allocation proposals, the revenue-cost ratio correctly indicates when there is progress toward cost-based rates and when there is not.

The only downside to this unadjusted revenue-cost ratio approach is that the progress toward cost-based rates in the current case is not the same as that going into the next base rates case. This results because the mix of operating costs allocated to each class is different from the mix of rate base costs. This minor distortion is addressed in the final metric below.

Normalized Revenue-Cost Ratio

The normalized revenue-cost ratio makes a technical correction to the revenue-cost ratio metric to reduce the distortion associated with using a non-cost parameter, namely the residual return and income tax costs, as a measure of cost at current rates. This metric uses fully allocated costs including the utility's allowed return on capital as the cost metric at both current and proposed rates. In this metric, however, the revenues at current rates are "normalized" by applying the system average rate increase to each class. Thus, in this metric, the current rates revenue-cost ratio is the revenues that would be earned from each class if an across-the-board rate increase were applied divided by the fully allocated class revenue requirement. This is then compared to the revenue-cost ratio that results from the actual proposed revenue allocation.

As shown in the attached example, this metric correctly shows the progress toward cost-based rates in each of the scenarios, and it also correctly predicts what each class's revenue-cost performance will be going into the next base rates case if there is no change in the underlying cost structure.

Summary

The indexed rate of return is a metric that has intuitive appeal, in that cost-based rates are achieved when the index is at unity (1.0), and that it would seem therefore that moving the index closer to 1.0 would represent progress toward cost-based rates.

Alas, it is not that simple. As shown in the examples attached, and as evidenced in hundreds of utility rate proceedings in Pennsylvania, the indexed rate of return is not a reliable metric for gauging progress toward cost-based rates for any particular revenue allocation proposal. It may give a directionally correct answer, and it may not. And even when it does correctly show progress, it implies that there is much more progress toward cost-based rates than actually exists.

Of the five metrics evaluated in this review, the indexed rate of return is the only metric to fail the test and imply that there is progress toward cost-based rates when there is none, and even when rates are moving substantially away from allocated cost.

All the other metrics evaluated in this review are superior to the indexed rate of return approach. The dollar subsidy and differential rate of return have a modest disadvantage in that they may imply that there is no progress toward cost-based rates when in fact some small progress is occurring. This is a relatively modest disadvantage since the distortion is much smaller than that in the indexed rate of return, and moreso because it will encourage Pennsylvania utilities and regulators to adopt revenue allocation proposals that are more aggressive in moving revenues into line with allocated cost, consistent with the legal standard that cost of service be the polestar criterion.

Overall, however, the revenue-cost metric, particularly the normalized revenue-cost metric, does not suffer from the distortions of any of the other methods, and is the most reliable of the methods on offer.

EXHIBIT IEc-1

RÉSUMÉ AND EXPERT TESTIMONY LIST

FOR

MARK D. EWEN

and

ROBERT D. KNECHT

MARK D. EWEN **PRINCIPAL**

Overview

Mr. Ewen has a strong background in applied economics, empirical methodologies, and financial analysis. As a Principal at Industrial Economics, Incorporated (IEc), he focuses on expert case management and economic damages estimation in a variety of litigation contexts, regulatory and environmental economics, and financial analysis. Within his areas of expertise, Mr. Ewen has been qualified as an expert witness before judicial and regulatory bodies (see schedule of testimony and appearances). He has also served as a Managing Director of the firm.

Education

Master of Public Policy, University of Michigan

Bachelor of Arts, summa cum laude in Economics and Political Science, University of North Dakota

Project Experience

Examples of his project work include the following:

Mr. Ewen has participated in various proceedings concerning energy markets and regulated utilities. These efforts, which focus on issues related to cost allocation and rate design, include working on behalf of industry and consumer intervenor groups in rate-making cases before the public utility commissions in Pennsylvania and Alberta, Canada, and the U.S. Postal Rate Commission. For example, for the **PENNSYLVANIA OFFICE OF SMALL BUSINESS ADVOCATE**, he has provided consulting and analytic support relating to electricity and natural gas tariff design, revenue requirements, and other regulatory initiatives concerning electrical and natural gas distribution utilities. For the **RHODE ISLAND ATTORNEY GENERAL,** Mr. Ewen conducted a due diligence review of PPL's proposed acquisition of Narragansett Electric Company and its potential impacts on the state's ratepayers.

For the **NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY (NYSERDA) AND DEPARTMENT OF PUBLIC SERVICE (DPS)**, Mr. Ewen provided expert services assessing the economic impacts to municipal governments of extended electricity outages related to Tropical Storm Isaias. As part of this work, he constructed a model to estimate various costs of incremental staffing requirements for over 500 localities, including excess overtime, surge time (i.e., bringing on extra staff for outage response coordination and logistics), and idle time (e.g., crews waiting extended periods for downed lines to be de-energized). The review also included consideration of other direct costs, including, among others: effects to water systems; delivery of bottled water; operation of generators; and other constraints on the provision of essential governmental services. The litigation was settled to the satisfaction of the involved parties.

For the **NYSERDA AND NEW YORK DPS,** Mr. Ewen directed the development of a Generic Environmental Impact Statement (GEIS), pursuant to the requirement of the State Environmental Quality Review Act (SEQRA) that assessed the environmental and economic impacts of the "Reforming the Energy Vision" and "Clean Energy

Fund" initiatives within the state. He also directed the preparation of a Supplemental EIS to assess the environmental and economic impacts of the newly proposed Clean Energy Standard (CES). The CES is being developed to support the state's goal of supplying 50 percent of electricity demand with renewable generation resources by the year 2030. More recently, he directed the development of a model to assess the financial viability of various waste-to-energy technologies, and related social welfare benefits. This model uses detailed capital budgeting scenarios for specific facilities to generate forecast scenarios.

For the **U.S. DEPARTMENT OF THE INTERIOR, BUREAU OF OCEAN ENERGY MANAGEMENT (BOEM)**, directing an assessment of the Bureau's approach to calculating and presenting the operating fee included in offshore wind leases under BOEM's jurisdiction. As part of this engagement, IEc provided a number of recommendations for simplifying the implementation of the operating fee formula and identified available data sources and approaches to estimating individual components of the fee formula. The review also addressed the structure and levels of fees associated with operations of renewable wind energy projects in the U.S. and worldwide. More recently, IEc has been supporting the development of Standard Operating Procedures for the fee calculation and lease management process. The overall goal is to provide information resources and a methodological approach that will allow lessees to derive accurate data for fee equation variables efficiently and consistently, and for BOEM to present the fee calculation clearly in the lease.

For **NYSERDA,** conducting a market analysis examining the potential economic development opportunities that could accrue in New York from hydrogen playing a role in achieving components of its Climate Leadership and Community Protection Act.

For the **U.S. DEPARTMENT OF THE INTERIOR, BUREAU OF OCEAN ENERGY MANAGEMENT**, managed the development of a model to assess the economic and fiscal impacts of offshore oil and gas activity in the Gulf of Mexico and other BOEM OCS regions. This model, the Lifecycle Impacts Model (LCIM), assesses the economic and fiscal impacts associated with a specific lease or group of leases, over the time horizon of the lease(s). IEc's framework for the model was to build a capital budgeting forecasting tool for lease development, yielding estimates of industry expenditures, OCS revenues, industry profits, and employment impacts for a single lease or a set of leases. A key component of model development was to dynamically simulate the complex and unique timing parameters of lease development, incorporating the influence of critical exogenous factors like market prices and lease geology.

For the **U.S. COAST GUARD, NATIONAL POLLUTION FUNDS CENTER**, Mr. Ewen provides ongoing support to the NPFC in adjudicating damages claims resulting from oil spills. These claims include damages for business interruption, lost profits, property damage or value diminution, increased costs, and lost wages or employment, among other categories. Cases have also included damages for contract delays to construction projects and shipping demurrage. Industry sectors that Mr. Ewen has evaluated include: *electricity generation (nuclear and coal); railroads; cruise ships; oil ship transport; lodging and tourism; food and beverage; gambling; fisheries; marinas; real estate development, oil and gas development; and oil refining.*

Mr. Ewen's analytic work includes expert financial analysis and economic damages estimation in the context of general litigation and environmental enforcement actions. These efforts include assessing damages in breach of contract, nuisance, and cost recovery actions, and assessing the financial capabilities and economic benefit of noncompliance of firms accused of environmental violations. Clients in this area of his practice include the **U.S. DEPARTMENT OF JUSTICE**, **U.S. COAST GUARD**, **U.S. ENVIRONMENTAL PROTECTION AGENCY, STATES,** and private parties.

Testimony and Appearances

Mr. Ewen has provided testimony or appeared in the following cases and regulatory proceedings.

On behalf of Attorney General of the State of Rhode Island, submitted testimony before the Rhode Island Division of Public Utilities and Carriers concerning due diligence and related reviews of PPL Corporation's proposed acquisition of Narragansett Electric Company from National Grid USA (Docket No. D-21-09, November 2021).

Expert report and deposition testimony concerning economic damages and related financial matters, *Seaplane Adventures, LLC, vs. County of Marin, California*; expert report filed September 2021, deposition testimony given September 2021.

Expert reports and deposition testimony on bankruptcy reorganization plan feasibility and related financial matters, *in re: First Energy Solutions Corp., et al., Debtors, Case No. 18-50757*; expert reports filed July 2019, deposition testimony given August 9, 2019.

Expert declaration concerning economic damages and related financial matters, *in re: Outer Banks Power Outage Litigation, all actions, No. 4:17-CV-141-D*, March 2018.

Expert report and deposition testimony on Economic Damages in *State of Alaska v. Williams Alaska Petroleum, Inc., et al.*, *Case No. 4FA-14-01544 CI;* expert report filed December 2016, deposition testimony given February 15, 2017.

Expert reports and deposition testimony on Economic Benefit in *Sierra Club v. Energy Future Holdings Corp. et al., Case No. 5:10-cv-156 (E.D. Tex.)* and *Sierra Club v. Energy Future Holdings Corp. et al., Case No. 6:12-cv-108 (W.D. Tex.)*; expert reports filed in June and July 2013, deposition testimony given August 2013. Trial testimony given in Case No. *6:12-cv-108 (W.D. Tex.) in March 2014.*

Expert testimony on ability-to-pay provided, in the matter of Mercury Vapor Processing Technologies, Inc., et al. (No. RCRA-05-2010-0015), July 2011.

Expert Declaration in a patent case concerning economic and financial matters in the context of environmental credits valuation -- In re Patent Application of: Jeff Andrilenas et al., Application No.: 12/328,219, For: VALUING ENVIRONMENTAL CREDITS, submitted June 2011.

Export report and deposition testimony on financial matters in Evansville Greenway and Remediation Trust v. Southern Indiana Gas and Electric Company, Inc., et al. (03:07-cv-0066-SEB-WGH); expert report filed July 2009, deposition testimony given January 2010.

Expert testimony on ability-to-pay provided, in the matter of Robert J. Heser, Andrew J. Heser, and Heser Farms (No. CWA-05-2006-0002), May 2007.

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning tariff design issues for Columbia Gas of Pennsylvania (Docket No. R-00049783, May 2005).

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning cost allocation, revenue assignment, and rate design for Pennsylvania Power and Light (Docket No. R-00049255, August 2004).

Expert report on economic damages in United States v. Southern California Edison No. CIV. F-01-5167 OWW DLB (E.D. Cal)., July 2004; deposition testimony provided September 2004.

Expert testimony on ability-to-pay provided in U.S. v. Peter Thorson, Managed Investments, Inc., Construction Management, Inc., and Gerke Excavating, Inc. (No. 03-C-0074), May 2004.

Expert testimony on ability-to-pay provided in U.S. v. Paul A. Heinrich and Charles Vogel Enterprises, Inc. (No. 03-C-0075-S), October 2003.

Expert testimony on ability-to-pay provided in the matter of Dearborn Refining Company (No. RCRA-05-2001-0019), February 2003.

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning recovery of purchased gas costs and revenue sharing for PFG Gas and Northern Penn Gas (Docket No. R-00027389, July 2002).

Expert report and testimony on economic damages in Carol Marmo et al. v. IBP, Inc.; expert report filed March 2002, deposition testimony given June 2002, September 2004, and testimony at trial given February 2005.

On behalf of Pennsylvania's Office of Small Business Advocate, submitting testimony before the Pennsylvania Public Utility Commission, concerning recovery of purchased gas costs and revenue sharing for National Fuel Gas Distribution Corporation (Docket No. R-00016789, March 2002).

On behalf of the Office of the Consumer Advocate, providing testimony before the United States Postal Rate Commission regarding cost allocation of city carrier street time costs. Docket No. R2000-1, July 11, 2000.

Expert report and declaration on ability-to-pay in re Indspec Chemical Corporation and Associated Thermal Services, Inc., and related testimony in U.S. EPA administrative court on February 24, 1998 (No. CAA-III-086).

Expert report on ability-to-pay in re Harrisburg Hospital and First Capital Insulation, Inc. and related testimony in U.S. EPA administrative court on October 8, 1997 (No. CAA-III-076).

2022

Overview

Mr. Knecht has more than 40 years of economic consulting experience, focusing on the energy, utility, metals and mining industries. For the past 30 years, Mr. Knecht's practice has primarily involved providing analysis, consulting support and expert testimony in regulatory matters, primarily involving electric and natural gas utilities. Mr. Knecht's work includes many aspects of utility regulation, including industry restructuring, cost unbundling, cost allocation, rate design, rate of return, customer contributions, energy efficiency programs, smart metering programs, treatment of stranded costs and utility revenue requirement issues. He has consulted to state advocacy agencies, industrial customer groups, law firms, regulatory agencies, government agencies and utilities, in both the United States and Canada. He has provided expert testimony in more than one hundred separate utility proceedings.

In addition to his work with regulated utilities, Mr. Knecht has consulted on international industry restructuring studies, prepared economic policy analyses, participated in a variety of litigation matters involving economic damages, and developed energy industry forecasting models.

Mr. Knecht served as a Principal of IEc for 33 years, and as its Treasurer for 15 years. He is currently an independent consultant who remains affiliated with IEc.

Education

Master of Science, Management (Applied Economics and Finance), Sloan School of Management, M.I.T.

Bachelor of Science, Economics, Massachusetts Institute of Technology

Select Project Experience

For more than 25 years, Mr. Knecht has provided consulting services, analysis and expert testimony before the Pennsylvania Public Utility Commission on all manner of regulatory proceedings to the **PENNSYLVANIA OFFICE OF SMALL BUSINESS ADVOCATE**. In addition to expert testimony, Mr. Knecht has assisted OSBA with the development of public policy positions, litigation strategy, and longer term strategy.

For the **ATTORNEY GENERAL OF THE STATE OF RHODE ISLAND**, Mr. Knecht provided consulting and expert witness services in an acquisition proceeding involving PPL Corporation's proposed acquisition of Narragansett Electric from National Grid. Mr. Knecht's testimony addressed financial, economic, environmental, tax, operating cost and rate implications.

For the **NEW BRUNSWICK PUBLIC INTERVENER,** Mr. Knecht provides consulting and expert witness services in a variety of regulatory proceeding before the New Brunswick Energy and Utilities Board involving New Brunswick Power, Enbridge Gas New Brunswick, and petroleum products. Mr. Knecht has addressed issues of load forecasting, costs forecasting, cost of capital, allocation of corporate overhead costs, utility cost allocation, revenue allocation, market-based rate design, cost-based rate design, and rate decoupling.

For **L'ASSOCIATION QUÉBÉCOISE DES CONSOMMATEURS INDUSTRIELS D'ÉLECTRICITÉ (AQCIE) AND LE CONSEIL DE L'INDUSTRIE FORESTIÈRE DU QUÉBEC (CIFQ)**, Mr. Knecht provided analysis, consulting advice and expert testimony before the Régie de l'énergie in regulatory matters involving Hydro Québec Distribution and TransÉnergie. This work includes revenue requirement, power purchasing, cost allocation, treatment of cross-subsidies, and rate design.

For the **INDEPENDENT POWER PRODUCERS SOCIETY OF ALBERTA**, Mr. Knecht provided consulting advice, analysis and expert testimony before the Alberta Energy and Utilities Board in a series of proceedings involving the restructuring of the electric utility industry, the unbundling of rates, and the development of transmission rates.

EXHIBIT IEc-2

IEc ELECTRONIC WORKPAPERS

IEc WP1: Columbia Proposed Proof of Revenues

IEc WP2: Replication of Columbia P&A ACOSS

IEc WP3: IEc Alternative P&A ACOSS

IEc WP4: FPFTY Design Day Analysis

IEc WP5: Metrics for Progress Toward Cost-Based Rates

Workpapers in Excel format will be distributed simultaneous to email distribution of Direct Testimony

Comparison of Alternative Metrics for Evaluating Progress Toward Cost-Based Rates: Indexed Rate of Return Metric

		Across-The-Board Increase			Higher Class B Increase		
		Total	Class A	Class B	Total	Class A	Class B
	Current Rates						
(1)	Current Revenue	100,000	50,000	50,000	100,000	50,000	50,000
(2)	O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000
(3)	Pre-Tax Return (Difference)	30,000	10,000	20,000	30,000	10,000	20,000
(4)	Rate Base	750,000	400,000	350,000	750,000	400,000	350,000
(5)	Class Rate of Return (3)/(4)	4.00%	2.50%	5.71%	4.00%	2.50%	5.71%
(6)	Indexed Rate of Return	1.000	0.625	1.429	1.000	0.625	1.429
	Proposed Rates						
(7)	Rate Increase (%)	30.0%	30.0%	30.0%	30.0%	25.0%	35.0%
(8)	Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500
(9)	O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000
(10)	Pre-Tax Return (Difference)	60,000	25,000	35,000	60,000	22,500	37,500
(11)	Rate Base	750,000	400,000	350,000	750,000	400,000	350,000
(12)	Class Rate of Return (10)/(11)	8.00%	6.25%	10.00%	8.00%	5.63%	10.71%
(13)	Indexed Rate of Return	1.000	0.781	1.250	1.000	0.703	1.339
(14)	Progress Toward Cost Based Rates		42%	42%		21%	21%
	Next Base Rates Case						
(15)	Cost Increase (%)	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
(16)	Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500
(17)	O&M/A&G Cost	91,000	52,000	39,000	91,000	52,000	39,000
(18)	Pre-Tax Return (Difference)	39,000	13,000	26,000	39,000	10,500	28,500
(19)	Rate Base	975,000	520,000	455,000	975,000	520,000	455,000
(20)	Class Rate of Return (3)/(4)	4.00%	2.50%	5.71%	4.00%	2.02%	6.26%
(21)	Indexed Rate of Return	1.000	0.625	1.429	1.000	0.505	1.566
(22)	Progress Toward Cost Based Rates		0%	0%		-32%	-32%
		Observation: Indexed rate of return indicates that there is progress toward cost-based rates in current proceeding, but increases will never close the gap, as shown by next base rates case.			**Observation:** Indexed rate of return indicates that there is progress toward cost-based rates in current proceeding, but rates going into next proceeding are farther away from cost than for current case.		

		Slightly Higher Class A Increase			Higher Class A Increase		
		Total	Class A	Class B	Total	Class A	Class B
	Current Rates						
(1)	Current Revenue	100,000	50,000	50,000	100,000	50,000	50,000
(2)	O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000
(3)	Pre-Tax Return (Difference)	30,000	10,000	20,000	30,000	10,000	20,000
(4)	Rate Base	750,000	400,000	350,000	750,000	400,000	350,000
(5)	Class Rate of Return (3)/(4)	4.00%	2.50%	5.71%	4.00%	2.50%	5.71%
(6)	Indexed Rate of Return	1.000	0.625	1.429	1.000	0.625	1.429
	Proposed Rates						
(7)	Rate Increase (%)	30.0%	32.0%	28.0%	30.0%	35.0%	25.0%
(8)	Proposed Revenue	130,000	66,000	64,000	130,000	67,500	62,500
(9)	O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000
(10)	Pre-Tax Return (Difference)	60,000	26,000	34,000	60,000	27,500	32,500
(11)	Rate Base	750,000	400,000	350,000	750,000	400,000	350,000
(12)	Class Rate of Return (10)/(11)	8.00%	6.50%	9.71%	8.00%	6.88%	9.29%
(13)	Indexed Rate of Return	1.000	0.813	1.214	1.000	0.859	1.161
(14)	Progress Toward Cost Based Rates		50%	50%		63%	63%
	Next Base Rates Case						
(15)	Cost Increase (%)	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
(16)	Proposed Revenue	130,000	66,000	64,000	130,000	67,500	62,500
(17)	O&M/A&G Cost	91,000	52,000	39,000	91,000	52,000	39,000
(18)	Pre-Tax Return (Difference)	39,000	14,000	25,000	39,000	15,500	23,500
(19)	Rate Base	975,000	520,000	455,000	975,000	520,000	455,000
(20)	Class Rate of Return (3)/(4)	4.00%	2.69%	5.49%	4.00%	2.98%	5.16%
(21)	Indexed Rate of Return	1.000	0.673	1.374	1.000	0.745	1.291
(22)	Progress Toward Cost Based Rates		13%	13%		32%	32%
		Observation: Indexed rate of return indicates that there is significant progress toward cost-based rates in current proceeding, but rates going into next case show only modest progress.			**Observation:** Indexed rate of return exaggerates progress toward cost-based rates in current proceeding.		

Comparison of Alternative Metrics for Evaluating Progress Toward Cost-Based Rates: Dollar Subsidy Metric

	Across-The-Board Increase			Higher Class B Increase			Slightly Higher Class A Increase			Higher Class A Increase		
	Total	Class A	Class B	Total	Class A	Class B	Total	Class A	Class B	Total	Class A	Class B
Current Rates												
(1) Current Revenue	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000
(2) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(3) Pre-Tax Return (Allocated)	30,000	16,000	14,000	30,000	16,000	14,000	30,000	16,000	14,000	30,000	16,000	14,000
(4) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(5) Cost of Service (2)+(3)	100,000	56,000	44,000	100,000	56,000	44,000	100,000	56,000	44,000	100,000	56,000	44,000
(6) Subsidy	0	-6,000	6,000	0	-6,000	6,000	0	-6,000	6,000	0	-6,000	6,000
Proposed Rates												
(7) Rate Increase (%)	30.0%	30.0%	30.0%	30.0%	25.0%	35.0%	30.0%	32.0%	28.0%	30.0%	35.0%	25.0%
(8) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(9) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(10) Pre-Tax Return (Allocated)	60,000	32,000	28,000	60,000	32,000	28,000	60,000	32,000	28,000	60,000	32,000	28,000
(11) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(12) Cost of Service	130,000	72,000	58,000	130,000	72,000	58,000	130,000	72,000	58,000	130,000	72,000	58,000
(13) Subsidy	0	-7,000	7,000	0	-9,500	9,500	0	-6,000	6,000	0	-4,500	4,500
(14) Progress Toward Cost Based Rates		-17%	-17%		-58%	-58%		0%	0%		25%	25%
Next Base Rates Case												
(15) Cost Increase (%)	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
(16) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(17) O&M/A&G Cost	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000
(18) Pre-Tax Return (Allocated)	39,000	20,800	18,200	39,000	20,800	18,200	39,000	20,800	18,200	39,000	20,800	18,200
(19) Rate Base	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000
(20) Cost of Service	130,000	72,800	57,200	130,000	72,800	57,200	130,000	72,800	57,200	130,000	72,800	57,200
(21) Subsidy	0	-7,800	7,800	0	-10,300	10,300	0	-6,800	6,800	0	-5,300	5,300
(22) Progress Toward Cost Based Rates		-30%	-30%		-72%	-72%		-13%	-13%		12%	12%
	Observation: Dollar subsidy correctly indicates that shortfall from Class B increases under proposed rates, and that dollar subsidy will be worse in next base rates case. Subsidy in percentage terms, however, would be the same.			**Observation:** Dollar subsidy correctly indicates that shortfall from Class B increases under proposed rates, and that dollar subsidy will be worse in next base rates case.			**Observation:** Dollar subsidy metric shows no progress toward cost-based rates, although subsidy as a percentage of rates declines.			**Observation:** Dollar subsidy metric correctly shows progress toward cost-based rates.		

Comparison of Alternative Metrics for Evaluating Progress Toward Cost-Based Rates: Differential Rate of Return Metric

	Across-The-Board Increase			Higher Class B Increase			Slightly Higher Class A Increase			Higher Class A Increase		
	Total	**Class A**	**Class B**	**Total**	**Class A**	**Class B**	**Total**	**Class A**	**Class B**	**Total**	**Class A**	**Class B**
Current Rates												
(1) Current Revenue	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000
(2) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(3) Pre-Tax Return (Difference)	30,000	10,000	20,000	30,000	10,000	20,000	30,000	10,000	20,000	30,000	10,000	20,000
(4) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(5) Class Rate of Return (3)/(4)	4.00%	2.50%	5.71%	4.00%	2.50%	5.71%	4.00%	2.50%	5.71%	4.00%	2.50%	5.71%
(6) Differential Rate of Return	0.00%	-1.50%	1.71%	0.00%	-1.50%	1.71%	0.00%	-1.50%	1.71%	0.00%	-1.50%	1.71%
Proposed Rates												
(7) Rate Increase (%)	30.0%	30.0%	30.0%	30.0%	25.0%	35.0%	30.0%	32.0%	28.0%	30.0%	35.0%	25.0%
(8) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(9) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(10) Pre-Tax Return (Difference)	60,000	25,000	35,000	60,000	22,500	37,500	60,000	26,000	34,000	60,000	27,500	32,500
(11) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(12) Class Rate of Return (10)/(11)	8.00%	6.25%	10.00%	8.00%	5.63%	10.71%	8.00%	6.50%	9.71%	8.00%	6.88%	9.29%
(13) Differential Rate of Return	0.00%	-1.75%	2.00%	0.00%	-2.38%	2.71%	0.00%	-1.50%	1.71%	0.00%	-1.13%	1.29%
(14) Progress Toward Cost Based Rates		-17%	-17%		-58%	-58%		0%	0%		25%	25%
Next Base Rates Case												
(15) Cost Increase (%)	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
(16) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(17) O&M/A&G Cost	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000
(18) Pre-Tax Return (Difference)	39,000	13,000	26,000	39,000	10,500	28,500	39,000	14,000	25,000	39,000	15,500	23,500
(19) Rate Base	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000
(20) Class Rate of Return (3)/(4)	4.00%	2.50%	5.71%	4.00%	2.02%	6.26%	4.00%	2.69%	5.49%	4.00%	2.98%	5.16%
(21) Differential Rate of Return	0.00%	-1.50%	1.71%	0.00%	-1.98%	2.26%	0.00%	-1.31%	1.49%	0.00%	-1.02%	1.16%
(22) Progress Toward Cost Based Rates		0%	0%		-32%	-32%		13%	13%		32%	32%
	Observation: Return differential indicates that shortfall from Class B increases under proposed rates. However, under this metric, the differentials going into the next base rates case will be the same as those going into the current case, meaning there is no change either way.			**Observation:** Return differential metric correctly indicates that shortfall from Class B increases under proposed rates, and that the shortfall will be worse in next base rates case. Metric overstates impact of current case.			**Observation:** Return differential metric shows no progress toward cost-based rates in current case, although modest progress results as shown by results going into next base rates case.			**Observation:** Return differential metric correctly shows progress toward cost-based rates in current case, although that progress is modestly understated.		

Comparison of Alternative Metrics for Evaluating Progress Toward Cost-Based Rates: Revenue-Cost Ratio

	Across-The-Board Increase			**Higher Class B Increase**			**Slightly Higher Class A Increase**			**Higher Class A Increase**		
	Total	**Class A**	**Class B**	**Total**	**Class A**	**Class B**	**Total**	**Class A**	**Class B**	**Total**	**Class A**	**Class B**
Current Rates												
(1) Current Revenue	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000
(2) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(3) Pre-Tax Return (Allocated)	30,000	16,000	14,000	30,000	16,000	14,000	30,000	16,000	14,000	30,000	16,000	14,000
(4) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(5) Cost of Service (2)+(3)	100,000	56,000	44,000	100,000	56,000	44,000	100,000	56,000	44,000	100,000	56,000	44,000
(6) Revenue-Cost Ratio	100.0%	89.3%	113.6%	100.0%	89.3%	113.6%	100.0%	89.3%	113.6%	100.0%	89.3%	113.6%
Proposed Rates												
(7) Rate Increase (%)	30.0%	30.0%	30.0%	30.0%	25.0%	35.0%	30.0%	32.0%	28.0%	30.0%	35.0%	25.0%
(8) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(9) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(10) Pre-Tax Return (Allocated)	60,000	32,000	28,000	60,000	32,000	28,000	60,000	32,000	28,000	60,000	32,000	28,000
(11) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(12) Cost of Service	130,000	72,000	58,000	130,000	72,000	58,000	130,000	72,000	58,000	130,000	72,000	58,000
(13) Revenue-Cost Ratio	100.0%	90.3%	112.1%	100.0%	86.8%	116.4%	100.0%	91.7%	110.3%	100.0%	93.8%	107.8%
(14) Progress Toward Cost Based Rates		9%	11%		-23%	-20%		22%	24%		42%	43%
Next Base Rates Case												
(15) Cost Increase (%)	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
(16) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(17) O&M/A&G Cost	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000
(18) Pre-Tax Return (Allocated)	39,000	20,800	18,200	39,000	20,800	18,200	39,000	20,800	18,200	39,000	20,800	18,200
(19) Rate Base	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000
(20) Cost of Service	130,000	72,800	57,200	130,000	72,800	57,200	130,000	72,800	57,200	130,000	72,800	57,200
(21) Revenue-Cost Ratio	100.0%	89.3%	113.6%	100.0%	85.9%	118.0%	100.0%	90.7%	111.9%	100.0%	92.7%	109.3%
(22) Progress Toward Cost Based Rates		0%	0%		-32%	-32%		13%	13%		32%	32%
	Observation: Revenue-cost ratio metric shows slight progress toward cost-based rates in current case, even though no progress will have occurred going into the next base rates case.			**Observation:** Revenue-cost ratio metric correctly shows negative progress toward cost-based rates.			**Observation:** Revenue-cost ratio metric correctly shows progress toward cost-based rates, but modestly overstates the progress as compared to the results going into the next base rates case.			**Observation:** Revenue-cost ratio metric correctly shows progress toward cost-based rates, but modestly overstates the progress as compared to the results going into the next base rates case.		

Comparison of Alternative Metrics for Evaluating Progress Toward Cost-Based Rates: Normalized Revenue-Cost Ratio

	Across-The-Board Increase			**Higher Class B Increase**			**Slightly Higher Class A Increase**			**Higher Class A Increase**		
	Total	**Class A**	**Class B**	**Total**	**Class A**	**Class B**	**Total**	**Class A**	**Class B**	**Total**	**Class A**	**Class B**
Current Rates												
(1) Current Revenue	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000
(2) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(3) Full Pre-Tax Return (Allocated)	60,000	32,000	28,000	60,000	32,000	28,000	60,000	32,000	28,000	60,000	32,000	28,000
(4) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(5) Cost of Service (2)+(3)	130,000	72,000	58,000	130,000	72,000	58,000	130,000	72,000	58,000	130,000	72,000	58,000
(5) Revenue-Cost Ratio	76.9%	69.4%	86.2%	76.9%	69.4%	86.2%	76.9%	69.4%	86.2%	76.9%	69.4%	86.2%
(6) Normalized Revenue-Cost Ratio	100.0%	90.3%	112.1%	100.0%	90.3%	112.1%	100.0%	90.3%	112.1%	100.0%	90.3%	112.1%
Proposed Rates												
(7) Rate Increase (%)	30.0%	30.0%	30.0%	30.0%	25.0%	35.0%	30.0%	32.0%	28.0%	30.0%	35.0%	25.0%
(8) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(9) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(10) Pre-Tax Return (Allocated)	60,000	32,000	28,000	60,000	32,000	28,000	60,000	32,000	28,000	60,000	32,000	28,000
(11) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(12) Cost of Service	130,000	72,000	58,000	130,000	72,000	58,000	130,000	72,000	58,000	130,000	72,000	58,000
(13) Revenue-Cost Ratio	100.0%	90.3%	112.1%	100.0%	86.8%	116.4%	100.0%	91.7%	110.3%	100.0%	93.8%	107.8%
(14) Progress Toward Cost Based Rates		0%	0%		-36%	-36%		14%	14%		36%	36%
Next Base Rates Case												
(15) Cost Increase (%)	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
(16) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(17) O&M/A&G Cost	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000
(18) Full Pre-Tax Return (Allocated)	78,000	41,600	36,400	78,000	41,600	36,400	78,000	41,600	36,400	78,000	41,600	36,400
(19) Rate Base	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000
(20) Cost of Service	169,000	93,600	75,400	169,000	93,600	75,400	169,000	93,600	75,400	169,000	93,600	75,400
(20) Revenue-Cost Ratio	76.9%	69.4%	86.2%	76.9%	66.8%	89.5%	76.9%	70.5%	84.9%	76.9%	72.1%	82.9%
(21) Normalized Revenue-Cost Ratio	100.0%	90.3%	112.1%	100.0%	86.8%	116.4%	100.0%	91.7%	110.3%	100.0%	93.8%	107.8%
(22) Progress Toward Cost Based Rates		0%	0%		-36%	-36%		14%	14%		36%	36%

Across-The-Board Increase — Observation:

Normalized revenue-cost ratio metric correctly shows zero progress toward cost-based rates.

Higher Class B Increase — Observation:

Normalized revenue-cost ratio metric correctly shows negative progress toward cost-based rates.

Slightly Higher Class A Increase — Observation:

Normalized revenue-cost ratio metric correctly shows progress toward cost-based rates.

Higher Class A Increase — Observation:

Normalized revenue-cost ratio metric correctly shows progress toward cost-based rates.

EXHIBIT IEc-3

REFERENCED INTERROGATORY RESPONSES

OSBA-I-6

OSBA-I-7

OSBA-I-8

OSBA-II-1

OSBA-II-2

OSBA-II-4

OSBA-II-5

Interrogatory Responses in Excel format will be distributed simultaneous to email distribution of Direct Testimony

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

OFFICE OF SMALL BUSINESS ADVOCATE INTERROGATORIES
Set 1

Question No. OSBA 1-006:

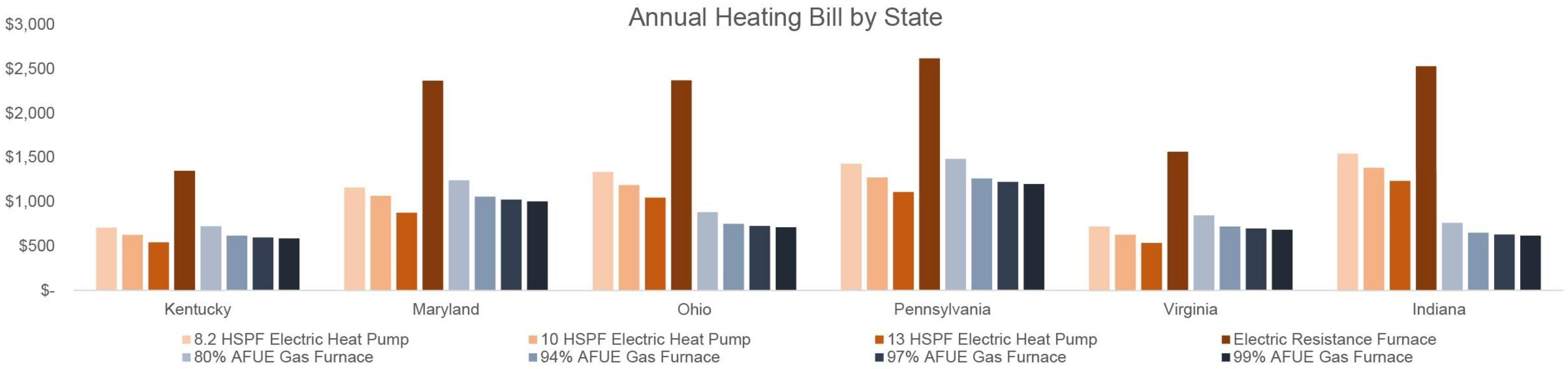
Please provide a copy of the Company's most recent competitive analysis between delivered natural gas and heat pump/mini-split electric heating for residential and small commercial customers in its service territory.

Response:

The Company has only looked at operating costs of typical natural gas furnaces compared to electric heat pumps and resistance furnaces. The Company has not done any analysis on mini-splits. Please refer to Attachment A to this response for the comparison using average usage for a residential customer. No analysis has been done for small commercial customers.

HEATING WITH GAS IS CHEAPER IN MOST STATES

- In most cases, the comparable model for electric heating is significantly more expensive than gas
- Using a higher efficiency gas furnace (94%-99%) can lower customers heating bill



Electric vs. Gas Heating Annual Cost Difference (Comparable Models)	Kentucky	Maryland	Ohio	Pennsylvania	Virginia	Indiana
Electric Resistance Furnace vs. 80% AFUE Gas Furnace	$622.59	$1,122.72	$1,487.48	$1,133.67	$714.70	$1,767.16
8.2 HSPF Electric Heat Pump vs. 94% AFUE Gas Furnace	$91.33	$104.30	$585.63	$164.05	$0.89	$892.67
10 HSPF Electric Heat Pump vs. 97% AFUE Gas Furnace	$28.69	$41.77	$459.76	$48.48	($69.75)	$752.73
13 HSPF Electric Heat Pump vs. 99% AFUE Gas Furnace	($43.88)	($126.39)	$332.86	($89.85)	($146.69)	$617.65

Note: Annual cost difference calculated as electric cost minus gas cost; Positive indicates electric is **more** expensive; Negative indicates electric is **less** expensive

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

OFFICE OF SMALL BUSINESS ADVOCATE INTERROGATORIES
Set 1

Question No. OSBA 1-007:

Reference Columbia 2017 LTIIP page 15, Columbia Statement No. 7 page 7, Columbia Statement No. 1 Figure 4:

a. Please provide the actual mileage and capital costs incurred associated with the mains replacement for each year for each category as reported in Statement No. 1 Figure 4 in tabular form.
b. Please provide the capital cost associated with the mains replacement values in the table in Statement No. 7, page 7, for each year, total and per foot.
c. Please provide the current estimated and forecast values for 2022 and 2023 for mains replacement and associated capital cost, for the categories shown in Figure 4.
d. Please provide the LTIIP capital cost estimate for the mains replacements shown in the table on page 15 of the LTIIP.
e. Please explain any material differences between the LTIIP and current forecasts for mains replacement in 2022 and 2023, both in terms of footage replaced and per-foot replacement costs.

Response:

a. Please see OSBA 1-007 Attachment A. This includes all mainline replacement installations (Job Types 557, 559, and 561). The annual capital cost and cost per foot (or per mile) for mainline replacement are reflected as the total overall cost. Annual capital costs and costs per foot (or per mile) are not tracked at a pipe category level.

b. Please see the response to "a".

c. Please see OSBA 1-005 with regards to the Company's Age & Condition Infrastructure Replacement Program.

d. Please see Table 1 below:

Table 1

Year	Total Pipe Retired in Miles	Priority Pipe Retired in Miles	Expenditures in Millions Age & Condition - Mainline Only Betterment - Mainline Only Public Improvement - Mainline Only
2007	79.7	67.4	$33.00
2008	127.5	100.1	$49.03
2009	78.4	65.2	$38.30
2010	78.0	61.1	$40.32
2011	134.8	104.9	$78.64
2012	114.8	78.6	$84.07
2013	127.1	85.7	$107.52
2014	125.3	78.3	$102.35
2015	139.7	94.1	$118.23
2016	136.7	90.7	$135.70
2017	147.8	96.5	$170.26
2018	103.3	57.3	$126.27
2019	155.8	97.9	$189.45
2020	131.2	73.5	$189.26
2021	140.5	83.3	$159.70

e. At this time there are no significant differences between the LTIIP and the current forecasts for main replacements in 2022 and 2023 with the exception of $8.4 million and $22.5 million currently allocated and projected to be spent respectively on In Line Inspections as explained in testimony. With regard to per foot replacement costs, please see OSBA 1-008.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

OFFICE OF SMALL BUSINESS ADVOCATE INTERROGATORIES
Set 1

Question No. OSBA 1-008:

Reference Columbia Statement No. 7, page 13:

a. Please provide supporting calculations for the replacement cost of $238 per foot for 2021, with estimates for 2022 and 2023.

Response:

Please see OSBA 1-008 Attachment A.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

OFFICE OF SMALL BUSINESS ADVOCATE INTERROGATORIES
Set 2

Question No. OSBA 2-001:

Reference Exhibit 111, Schedule 2, Alloc 1:

a. In MS Excel electronic format, please provide workpapers for the development of the design day demand allocator. If these demands were derived in another proceeding, please provide the workpapers from that proceeding.
b. Please identify any changes made in the method for deriving design day demands in this proceeding compared to the Company's last base rates case.
c. To the extent known, please provide the reasons for the material reduction in class load factor for the SGS1 and SGS2 classes since the last base rates case.
d. In MS Excel electronic format, please provide monthly calendarized loads for each rate class (as defined in the cost allocation study), with the associated heating degree days for each month.

Response:

a. Please see OSBA-02-001 Attachment A (in MS Excel) that provides the workpapers for the design day allocator. The quantities contained in the design day factor represent the total demand projected to occur at Columbia's design peak day and were based on peak month demands (January 2021) as shown in Attachment A.

b. There were no changes made in the method for deriving the design day demands in this proceeding compared to the last base rate case. However, the last base rate case did not include firm obligation capacity related to Standby and Elective Balancing Services ("EBS") in the calculation of the design day allocator. The firm demand quantities are detailed on Page 5 (the tab Sch 9) of OSBA-02-001 Attachment A under the column "Additional Firm Obligation". The EBS firm obligation capacity amounts are shown on Line 20 on Exhibit 111, Schedule 2, Alloc 1. The Standby amounts (5.8 million) were applied to the SDS/LGSS class (Line 6 on Exhibit 111, Schedule 2, Alloc 1) and the LDS/LGSS (Line 4 on Exhibit 111, Schedule 2, Alloc 1).

These Standby and EBS quantities were inadvertently excluded in the prior base rate cases. However, they were appropriately included in this base rate case because they represent the firm requirements of transportation customers at design day temperatures.

c. The SGS/DS-1 and SGS/DS-2 demands in the current case were 87,000 and 106,200, respectively. The SGS/DS-1 and SGS/DS-2 demands in the last base rate case were 77,700 and 101,000, respectively. Both rate classes showed increased demands compared to the last case.

d. Please see OSBA-02-001 Attachment B (in MS Excel) showing the monthly calendarized loads for each rate class as defined in the cost allocation study. The twelve months detailed include monthly throughput for the fully projected future test year (TME 12/2023). Heating Degree Days ("HDD") for each month are also provided.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

OFFICE OF SMALL BUSINESS ADVOCATE INTERROGATORIES
Set 2

Question No. OSBA 2-002:

Reference Exhibit 111, Schedule 2, Alloc 3 and Alloc 5:

a. Please explain the difference between the Flex volume in Alloc 3 and the Flex volume in Alloc 5.
b. Are Flex Rate MDS mains costs directly assigned? If so, are Flex Rate MDS volumes included in the P&A allocator?
c. Please provide the "Flex Workpaper" referenced in the note in cell I27 in worksheet Alloc 2, 3 & 25 Throughputs, in MS Excel electronic format.

Response:

a. The Flex volumes in Alloc 3 and Alloc 5 should be the same. The formula in Alloc 5 should have pulled the Flex volumes on Line 21 of Alloc 3 (9,070,033) that excludes MDS throughput instead of Line 17 (11,978,033) that includes MDS throughput. It is important to note that with this correction, the Company continues to believe that its proposed revenue apportionment and rate design is still appropriate.

b. Flex Rate MDS mains costs are directly assigned. Flex Rate MDS volumes should not be included in the P&A allocator. Please see the response to part a. above discussing the correction of Flex MDS volumes in the P&A allocator.

c. The Flex Workpapers note referred to in cell I27 can be found in the response to Data Request OCA 4-002 in OCA 4-002 Attachment D – Highly Confidential and OCA 4-002 Attachment E – Highly Confidential.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

OFFICE OF SMALL BUSINESS ADVOCATE INTERROGATORIES
Set 2

Question No. OSBA 2-004:

Reference Exhibit 111, Schedule 2, Alloc 15 services:

a. Please explain why the plant values for the MDS/NSS and Flex classes in this worksheet appear to be higher than those used in the direct assignment of services plant at page 3.
b. Please confirm that there are two SGSS/SCD/SGDS (one in group 1, one in group 2) customers with 12" service lines, each with an assumed cost of $97,758. Please explain why these relatively small customers have 12" service lines.
c. For worksheet Services-Plant Records, please define "quantity."
d. In worksheet Services-AUC, please explain why unit cost values are adjusted for service length for only certain service diameters.

Response:

a. The plant values for the MDS/NSS and Flex classes in this worksheet are calculated by applying the number of Service lines for the Rate Class to the average cost per Service line based on the size of the customer's Service line. The direct assignment of Services plant associated with the MDS/NSS and Flex class customers represents a direct inventory cost of the specific service lines that serve these customers.

b. The two customers with the 12 inch service lines relate to a church and a university. The university customer is served off a service line that is shared with another large volume university account. The service line for the church account is coded 120 in the customer information system ("DIS"). Code 120 identifies the service line as 12". As part of responding to this data request, the Company asked for verification from field personnel to determine if it was possible that the service line for the church could be 1-1/4” as the service line code for 1-1/4” is 12. Field personnel responded that the code in the system should have been 12 instead of 120 and has made the appropriate correction in the system.

c. The quantity on Services-Plant Records represents the number of feet.

d. In 2021, Columbia change how Service line quantity was recorded on the Company’s plant accounting records. Service line quantity recorded before 2021 was counted as number of service lines. Service line quantity recorded in 2021 and in the future are recorded by footage of Service line pipe. Quantities before 2021 were converted to footage based on the following conversion: Each Main to Curb Service line was assigned 17 feet, each Curb to Meter Service line was assigned 45 feet, and each Main to Meter was assigned 62 feet.

As a result, those Service line sizes that did not add any footage in 2021 were straight conversions of footage back to number of service lines to determine an Average Unit Cost. As for those Service line sizes that now have quantities made up of footage of pipe that can no longer be used to determine an Average Cost per customer, Columbia now uses the customer count from DIS by Service line size to determine an Average Unit Cost.

Columbia Gas of Pennsylvania, Inc.

COLUMBIA GAS OF PENNSYLVANIA, INC.
2022 RATE CASE PROCEEDING

Docket No. R-2022-3031211

Data Requests

OFFICE OF SMALL BUSINESS ADVOCATE INTERROGATORIES
Set 2

Question No. OSBA 2-005:

Reference Exhibit 111, Schedule 2, Vlookup Alloc Table, Alloc 10:

a. Please confirm that the Company has inadvertently excluded the Flex rate customer forfeited discount amount in the total in cell E11.
b. Please confirm that a similar error exists in Cell E2 regarding the design day demand allocator, but Allocator 1 is not used directly for cost allocation.

Response:

a. I confirm that the Company has inadvertently excluded the Flex rate customer forfeited discount amount in the total in cell E11. It is important to note that with this correction, the Company continues to believe that its proposed revenue apportionment and rate design is still appropriate.

b. I confirm that a similar error exists in Cell E2 regarding the design day demand allocator, but Allocator 1 is not used directly for cost allocation and has no impact on the Company's proposed revenue apportionment and rate design.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**Docket No. R-2022-3031211**
	:	
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	
	:	

VERIFICATION

I, Mark D. Ewen, hereby state that the facts set forth in the Direct Testimony labelled OSBA Statement No. 1 and associated Exhibits IEc-1 through IEc-2 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: June 7, 2022

Mark Ewen

Mark D. Ewen

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**Docket No. R-2022-3031211**
	:	
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in the Direct Testimony labelled OSBA Statement No. 1 and associated Exhibits IEc-1 through IEc-2 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: June 7, 2022

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2022-3031211**
	:	
Columbia Gas of Pennsylvania, Inc.	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless other noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

Thomas J. Sniscak, Esquire
Whitney E. Snyder, Esquire
Phillip D. Demanchick, Jr., Esquire
Hawke McKeon & Sniscak LLP
100 North Tenth Street
Harrisburg, PA 17101
tjsniscak@hmslegal.com
wesnyder@hmslegal.com
pddemanchick@hmslegal.com

Amy E. Hirakis, Esq.
Theodore J. Gallagher, Esq
Columbia Gas of Pennsylvania, Inc.
800 North 3rd Street, Suite 204
Harrisburg, PA 17102
tjgallagher@nisource.com
ahirakis@nisource.com

Erika McLain, Esq.
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120
ermclain@pa.gov

Charis Mincavage, Esquire
Kenneth Stark, Esquire
McNees Wallace & Nurick LLC
100 Pine Street
Harrisburg, PA 17101
cmincavage@mcneeslaw.com
kstark@mcneeslaw.com

Todd S. Stewart, Esquire
Hawke McKeon & Sniscak LLP
100 North Tenth Street
Harrisburg, PA 17101
tsstewart@hmslegal.com

Michael W. Hassell, Esquire
Lindsay A Berkstresser, Esquire
Post & Schell PC
17 North Second Street
12th Floor
Harrisburg, PA 17101-1601
mhassell@postschell.com
lberkstresser@postschell.com

Lauren E. Guerra, Esq.
Barrett C. Sheridan, Esq.
Harrison W. Breitman, Esq.
Darryl A. Lawrence, Esq.
Office of Consumer Advocate
555 Walnut Street
5th Floor Forum Place
Harrisburg, PA 17101-1923
lguerra@paoca.org
BSheridan@paoca.org
HBreitman@paoca.org
abeatty@paoca.org

Joseph L. Vullo, Esquire
Burke Vullo Reilly Roberts
1460 Wyoming Avenue
Forty Fort, PA 18704
jlvullo@bvrrlaw.com

John W. Sweet, Esq.
Ria M. Pereira, Esq.
118 Locust Street
Harrisburg, PA 17101
717-710-3839
pulp@palegalaid.net

The Honorable Christopher P. Pell
Deputy Chief Administrative Law Judge
Commonwealth of Pennsylvania
Pennsylvania Public Utility Commission
801 Market Street, Suite 4063
Philadelphia, PA 19107

Jennifer E. Clark, Esq.
Fair Shake Environmental Legal Services
100 S. Juniper St.
3rd Floor
Philadelphia, PA 19107
jclark@fairshake-els.org

Andrew Karas
Mark Szybist
Natural Resources Defense Council
1152 15th St. NW, Suite 300
Washington, DC 20005
akaras@fairshake-els.org
mszybist@nrdc.org

/s/ Steven C. Gray

DATE: June 7, 2022

____
Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

COMMONWEALTH OF PENNSYLVANIA

July 6, 2022

The Honorable Christopher P. Pell
The Honorable John Coogan
Commonwealth of Pennsylvania
Pennsylvania Public Utility Commission
801 Market Street, Suite 4063
Philadelphia, PA 19107

**Re: Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc.
2022 Base Rate Filing / Docket No. R-2022-3031211**

Dear Judge Pell and Judge Coogan :

Enclosed please find the Rebuttal Testimony and Exhibit of Robert D. Knecht and Mark D. Ewen, labeled OSBA Statement No.1-R, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney I.D. No. 77538

Enclosures

cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Robert D. Knecht
Mark Ewen
Parties of Record

OSBA Statement No. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**Docket No. R-2022-3031211**
	:	
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	
	:	

Rebuttal Testimony and Exhibit of

MARK D. EWEN and

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation

Date Served: July 6, 2022

Date Submitted for the Record: August 3, 2022

REBUTTAL TESTIMONY OF MARK D. EWEN and ROBERT D. KNECHT

1. Introduction and Context

Q. Mr. Ewen, Mr. Knecht, please state your names and briefly describe your qualifications.

A. Our names are Mark D. Ewen and Robert D. Knecht. We submitted direct testimony as associated exhibits on behalf of the Pennsylvania Office of Small Business Advocate earlier in these proceedings and our qualifications were presented therein.

Q. What is the purpose of this rebuttal testimony?

A. This rebuttal testimony responds to the cost allocation and revenue allocation recommendations of Mr. Jerome D. Mierzwa representing the Pennsylvania Office of Consumer Advocate ("OCA"), Mr. Ethan H. Cline representing the Commission's Bureau of Investigation and Enforcement ("I&E"), and Mr. James L. Crist, P.E., representing the Pennsylvania State University ("Penn State").

2. Cost Allocation

Q. What are the positions of the various parties regarding the appropriate cost allocation method for this proceeding?

A. As we explained in our direct testimony, the Company offered three allocated cost of service studies ("ACOSSs"), consistent with past practice. These three simulations of the ACOSS model differ only in how mains costs are allocated. They include a customer-demand ("CD") approach, and 50/50 peak-and-average ("P&A") approach, and an average of the two ("AVG"). The Company indicates that it relies primarily on the P&A approach, based upon prior Commission precedent.

Mr. Cline and Mr. Mierzwa both rely on the Company's P&A ACOSS as the cost basis for revenue allocation and rate design. Neither witness proposes any methodological or technical adjustments to the Company's model.

Mr. Christ opines that the cost allocation of the revenue requirement yielded by the CD approach is most consistent with cost causation principles. His conclusion primarily is based on the reasoning that gas mains costs are incurred to attach customers to the system and are sized to meet peak demand. He argues that, at the least, the average of the CD and P&D studies be adopted.

Q. What is your position regarding the appropriate cost allocation method for this proceeding?

A. As a theoretical matter, we agree with Mr. Crist that economies of scale exist for serving larger customers. For reasons of Commission precedent, however, we rely on the P&A ACOSS as the cost basis for revenue allocation and rate design.

We do note that our direct testimony identified certain necessary adjustments to the P&A ACOSS. First, in reviewing the Company's throughput and design day demands in this proceeding, we identified what appears to be a significant shift in either the behavior of customers or in the Company's method for deriving design day demands. To address this unexplained variance, we reallocated the design day demand for the Residential, SGS1 and SGS2 classes to reflect our statistical analysis of the Company's FPFTY load forecast. This change has the effect of producing load factors for those classes that are similar to those used in the Company's last base rates case. Second, we made certain other necessary technical corrections including: (a) modifying the volume value for Flex rate customer for mains allocations to correct a company-acknowledged error; (b) adjusting the services allocator for the SGS1 and SGS2 class to exclude two high-cost service lines from the allocator that do not apply to customers in that class; and (c) correcting a *de minimis* summation error in the ACOSS.

3. <u>Revenue Allocation</u>

Q. What are the positions of the various parties with respect to revenue allocation in this proceeding?

A. As noted in our direct testimony, the Company's proposed revenue allocation yields no material progress toward cost-based rates for Residential, SGS1 and SGS2 classes. In addition, because the revenue-cost ratio for the LDS/LGSS class is so low, an increase even at 1.5 times the system average results in little progress toward cost-based rates. The only classes to exhibit even moderate progress toward cost-based rates under the Company's propsal are the Medium General (SDS/LGSS) class (with an increase well above system average) and the MDS class (with no increase). Our analysis of this proposal indicated that the Company's inability to make material progress toward cost-based rates primarily lies with the gradualism constraints for the LDS/LGSS rate class.

We developed an alternative revenue allocation proposal that (a) relies on our modified ACOSS noted previously, (b) is somewhat more aggressive in attempting to move rates into line with allocated cost for the smaller customer classes, and (c) allows for a larger rate increase for the LDS/LGSS class to reflect the enormous revenue-cost difference under current rates.

Mr. Mierzwa offers an alternative revenue allocation proposal, which moderates the increase to the Residential class and sets aggressive increases for small and medium commercial classes.

Mr. Cline does not contest the Company's revenue allocation at the full revenue requirement. Rather, he offers a "first dollar relief" ("FDR") proposal under which the first $20 million of any reduction to the revenue requirement would be deducted from the Residential class increase proposed by the Company. Mr. Cline correctly notes that the Company and the Commission have failed to achieve any material progress toward cost-based rates for the Residential class over the past two rate proceedings. While some of that failure is related to cost shifts, we note that the indexed rate of return metric upon which Mr. Cline relies provides an illusory metric for progress toward cost-based rates within a single rate proceeding, which has disappeared when the next base rates case arrives. This phenomenon is explained in Appendix A of our direct testimony.

While Mr. Crist opines that the Commission should rely on the CD ACOSS methodology, he does not offer an alternative revenue allocation proposal.

Table IEc-1R summarizes the revenue allocation proposals.

Table IEc-1R Summary of Revenue Increase Allocation Proposals												
	Columbia			**OSBA**			**OCA**			**I&E FDR**		
	($mm)		**%**	**($mm)**		**%**	**($mm)**		**%**	**($mm)**		**%**
Residential	$	56.39	13.4%	$	54.05	12.9%	$	44.04	10.5%	$	35.79	8.5%
SGS1	$	6.92	14.4%	$	6.75	14.0%	$	10.90	22.6%	$	6.92	14.4%
SGS2	$	7.33	14.6%	$	8.10	16.2%	$	11.96	23.8%	$	7.33	14.6%
Med Gen'l (SDS/LGSS)	$	6.16	20.5%	$	6.35	21.1%	$	8.49	28.2%	$	6.76	22.5%
Lg Gen'l (LDS/LGSS)	$	5.25	22.0%	$	6.78	28.4%	$	6.75	28.2%	$	5.25	22.0%
MDS	$	-	0.0%	$	-	0.0%	$	-	0.0%	$	-	0.0%
Flex	$	0.01	0.3%	$	0.01	0.3%	$	0.01	0.3%	$	0.01	0.3%
Total	$	82.06	14.2%	$	82.06	14.2%	$	82.15	14.2%	$	62.06	10.7%

Note: The OCA increase includes increases in other non-rate revenues. Percentage increases for I&E calculated net of $20 million first dollar relief adjustment.
Source: IEc WP1-R

Q. Please address Mr. Mierzwa's proposal.

A. Table IEc-2R summarizes the impact of Mr. Mierzwa's proposal, using our cost allocation analysis inclusive of our reallocation of the flex rate customer shortfall.[1] For the reasons explained in our direct testimony, we use the revenue-cost ("R-C") ratio and each class's revenue increase relative to the system average as our metrics for evaluating the reasonableness of the proposals. And because is often serves as a rate gradualism constraint, we report the ratio of the class percentage increase to the system average increase.

[1] To allow for accurate reconciliation of this review to Mr. Mierzwa's analysis, we do adjust our calculation of current rate revenues and the proposed revenue requirement by not subtracting certain miscellaneous revenues from the total. We also note that in Table 2 of his direct testimony, the reported values for the "Proposed Rates" column appear to be in error. We therefore derive this review from the values in the "Increase" and "Percent" columns.

Table IEc-2R Analysis of OCA Proposed Revenue Allocation					
	Revenue-Cost Ratio			Class Increase (%)	Class to System Average Ratio
	Current	Proposed	Progress		
Residential	106.8%	103.3%	52%	10.5%	0.74
SGS1	100.8%	108.2%	-989%	22.6%	1.59
SGS2	94.5%	102.5%	146%	23.9%	1.68
Med Gen'l (SDS/LGSS)	83.2%	93.4%	61%	28.2%	1.99
Lg Gen'l (LDS/LGSS)	54.6%	61.4%	15%	28.2%	1.99
MDS	1308.9%	1146.5%	13%	0.0%	0.00
Flex	NM	NM	NM	0.3%	0.02
Total	100.0%	100.0%	--	14.2%	1.00

Flex rate cost performance is not meaningful because the $40 million shortfall is reallocated to other rate classes.

Source: IEc WP1-R

As shown in the table, Mr. Mierzwa's proposal has the following implications:

- The Residential class receives a below system average increase, yielding a substantial decline in subsidies from this class.

- The small business classes, SGS1 and SGS2, experience significant and unreasonable increases. Specifically, SGS1 rises from a subsidy neutral position to providing a substantial subsidy to other classes. The subsidy to SGS2 is fully reversed, and now provides a system subsidy under this proposal. In our experience before the Commission, it would be unprecedented for this type of revenue allocation to be proposed if it were the Residential class facing this effect.

- The proposed increase for the Medium General and Large General classes are similar relative to system average, despite the fact that the Medium General class's current R-C ratio is 83 percent and the Large General class is 55 percent. The proposed increase for these classes also yields much greater progress toward cost-based rates for the Medium General class (61 percent for Medium General and only 15 percent for Large General). This pattern is inequitable, particularly to Medium General Service ratepayers.

Based upon these findings, we conclude that Mr. Mierzwa's proposal is distortionary and inequitable, particularly to small business customers.

Q. Please address Mr. Cline's proposal.

A. Table IEc-3R below summarizes the impact of Mr. Cline's proposal, again using our cost allocation analysis and including the reallocation of the flex rate customer shortfall. To account for his FDR allowance, we have scaled back the overall increase by $20 million.

Table IEc-3R
Analysis of I&E Proposed Revenue Allocation

	R-C Ratio			**Class Increase (%)**	**Class to System Average Ratio**
	Current	**Proposed**	**Progress**		
Residential	106.8%	104.6%	32%	8.5%	0.79
SGS1	100.8%	104.1%	-428%	14.4%	1.34
SGS2	94.6%	97.9%	61%	14.6%	1.36
Med Gen'l (SDS/LGSS)	83.2%	92.0%	53%	22.5%	2.09
Lg Gen'l (LDS/LGSS)	54.6%	60.2%	12%	22.0%	2.05
MDS	1333.0%	1203.8%	10%	0.0%	-
Flex	NM	NM	NM	0.3%	0.03
Total	100.0%	100.0%		10.7%	1.00

Flex rate cost performance is not meaningful because $40 million shortfall is reallocated to other rate classes.

Source: IEc WP1-R

As a general matter, we agree that traditional "proportional scaleback" mechanisms for addressing an adjustment to the utility revenue requirement will serve to reduce progress toward cost-based rates, and that alternative FDR proposals may be considered. However, as shown in the table above, Mr. Cline's proposal has negative implications:

- Rate increases for two rate classes, Medium and Large General, modestly exceed the typical "rule of thumb" metrics for rate gradualism of 1.5 to 2.0 times system average.

- The subsidy *from* the SGS1 class increases substantially, moving significantly away from allocated cost. This result is inconsistent with Mr. Cline's analysis, the table on page 14 of his direct testimony would appear to indicate that subsidies from the

SGS1 class have been allowed to steadily increase over the past two base rates proceedings.

- The relative increase for the Medium General Service rate class is higher than that for the Large General Service rate class, despite a substantial difference in the current level of cross-subsidies.

Overall, we conclude that Mr. Cline's proposal is inconsistent with rate gradualism constraints in Pennsylvania, exacerbates subsidies provided by the SGS1 class, and assigns inequitable rate increases to the Medium and Large General Service rate classes.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT IEc-R1

IEc ELECTRONIC WORKPAPERS

IEc WPR1:

The workpapers is in Excel format will be distributed simultaneous to email distribution of Rebuttal Testimony

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**Docket No. R-2022-3031211**
	:	
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

VERIFICATION

I, Mark D. Ewen, hereby state that the facts set forth in the Rebuttal Testimony labelled OSBA Statement No. 1-R and associated Exhibit IEc-R1 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: July 6, 2022

Mark Ewen

Mark D. Ewen

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2022-3031211**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in the Rebuttal Testimony labelled OSBA Statement No. 1-R and associated Exhibit IEc-R1 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: July 6, 2022

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2022-3031211**
	:	
Columbia Gas of Pennsylvania, Inc.	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless other noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

Thomas J. Sniscak, Esquire
Whitney E. Snyder, Esquire
Phillip D. Demanchick, Jr., Esquire
Hawke McKeon & Sniscak LLP
100 North Tenth Street
Harrisburg, PA 17101
tjsniscak@hmslegal.com
wesnyder@hmslegal.com
pddemanchick@hmslegal.com

Amy E. Hirakis, Esq.
Theodore J. Gallagher, Esq
Columbia Gas of Pennsylvania, Inc.
800 North 3rd Street, Suite 204
Harrisburg, PA 17102
tjgallagher@nisource.com
ahirakis@nisource.com

Erika McLain, Esq.
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120
ermclain@pa.gov

Charis Mincavage, Esquire
Kenneth Stark, Esquire
McNees Wallace & Nurick LLC
100 Pine Street
Harrisburg, PA 17101
cmincavage@mcneeslaw.com
kstark@mcneeslaw.com

Todd S. Stewart, Esquire
Hawke McKeon & Sniscak LLP
100 North Tenth Street
Harrisburg, PA 17101
tsstewart@hmslegal.com

Michael W. Hassell, Esquire
Lindsay A Berkstresser, Esquire
Post & Schell PC
17 North Second Street
12th Floor
Harrisburg, PA 17101-1601
mhassell@postschell.com
lberkstresser@postschell.com

Lauren E. Guerra, Esq.
Barrett C. Sheridan, Esq.
Harrison W. Breitman, Esq.
Darryl A. Lawrence, Esq.
Office of Consumer Advocate
555 Walnut Street
5th Floor Forum Place
Harrisburg, PA 17101-1923
lguerra@paoca.org
BSheridan@paoca.org
HBreitman@paoca.org
abeatty@paoca.org

Joseph L. Vullo, Esquire
Burke Vullo Reilly Roberts
1460 Wyoming Avenue
Forty Fort, PA 18704
jlvullo@bvrrlaw.com

The Honorable Christopher P. Pell
Deputy Chief Administrative Law Judge
Commonwealth of Pennsylvania
Pennsylvania Public Utility Commission
801 Market Street, Suite 4063
Philadelphia, PA 19107
cpell@pa.gov

Jennifer E. Clark, Esq.
Fair Shake Environmental Legal Services
100 S. Juniper St.
3rd Floor
Philadelphia, PA 19107
jclark@fairshake-els.org

Andrew Karas
Mark Szybist
Natural Resources Defense Council
1152 15th St. NW, Suite 300
Washington, DC 20005
akaras@fairshake-els.org
mzybist@fairshake-els.org

Lafayette Morgan
Exeter Associates, Inc.
10480 Little Patuxent Pkwy, Suite 300
Columbia, MD 21044-3575
OCAColumbiaGas2022@paoca.org

Roger Colton
Fisher, Sheehan & Colton
34 Warwick Road
Belmont, MA 02478
OCAColumbiaGas2022@paoca.org

David Garrett
Resolve Utility Consulting PLLC
101 Park Avenue, Suite 1125
Oklahoma City, OK 73102
OCAColumbiaGas2022@paoca.org

John W. Sweet, Esq.
Ria M. Pereira, Esq.
118 Locust Street
Harrisburg, PA 17101
717-710-3839
pulp@palegalaid.net

James L. Crist, P.E.
Lumen Group, Inc.
4226 Yarmouth Drive, Suite 101
Allison Park, PA 15101
JLCrist@aol.com

Constance Wile
922 Bebout Road
Venetia, PA 15367
cjazdrmr@yahoo.com

Jose A. Serrano
2667 Chadbourne Drive
York, PA 17404
jas673@hotmail.com

Richard C. Culbertson
1430 Bower Hill Road
Pittsburgh, PA 15243
richard.c.culbertson@gmail.com

Jerome Mierzwa
Exeter Associates, Inc.
10480 Little Patuxent Pkwy, Suite 300
Columbia, MD 21044-3575
OCAColumbiaGas2022@paoca.org

James L. Crist, P.E.
Lumen Group, Inc.
4226 Yarmouth Drive, Suite 101
Allison Park, PA 15101
JLCrist@aol.com

Honorable John Coogan
Administrative Law Judge
Pennsylvania Public Utility Commission
Office of Administrative Law Judge
400 North Street
Harrisburg, PA 17120
jcoogan@pa.gov
sdelvillar@pa.gov

/s/ Steven C. Gray

DATE: July 6, 2022

____
Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

COMMONWEALTH OF PENNSYLVANIA

July 26, 2022

The Honorable Christopher P. Pell
Deputy Chief Administrative Law Judge
Commonwealth of Pennsylvania
Pennsylvania Public Utility Commission
801 Market Street, Suite 4063
Philadelphia, PA 19107

The Honorable John Coogan
Administrative Law Judge
Commonwealth of Pennsylvania
Pennsylvania Public Utility Commission
400 North Street
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc. 2022 Base Rate Filing / Docket No. R-2022-3031211

Dear Judge Pell and Judge Coogan :

Enclosed please find the Surrebuttal Testimony and Exhibit of Robert D. Knecht and Mark D. Ewen, labeled OSBA Statement No.1-S, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney I.D. No. 77538

Enclosures

cc: PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Robert D. Knecht
Mark Ewen
Parties of Record

OSBA Statement No. 1-S

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**Docket No. R-2022-3031211**
	:	
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	
	:	

Surrebuttal Testimony and Exhibit of

MARK D. EWEN and

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation

Date Served: July 26, 2022

Date Submitted for the Record: August 3, 2022

SURREBUTTAL TESTIMONY OF MARK D. EWEN and ROBERT D. KNECHT

1. Introduction and Context

Q. Mr. Ewen, Mr. Knecht, please state your names and briefly describe your qualifications.

A. Our names are Mark D. Ewen and Robert D. Knecht. We submitted direct testimony, rebuttal testimony and associated exhibits on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA") earlier in this proceeding and our qualifications were presented therein.

Q. What is the purpose of this rebuttal testimony?

A. This rebuttal testimony responds to the rebuttal testimony of Columbia Gas of Pennsylvania ("Columbia" or "the Company") witness Kevin L. Johnson and Pennsylvania Office of Consumer Advocate ("OCA") witness Jerome D. Mierzwa on matters of cost allocation and revenue allocation.

2. Cost Allocation

Q. Please summarize Witness Johnson's rebuttal testimony as it relates to your cost allocation recommendations.

A. In rebuttal, Witness Johnson presents a revised allocated cost of service study ("ACOSS") that reflects technical corrections to the Company's originally filed ACOSS as explained in our direct testimony, and adjustments to the design day demand allocation factors to exclude inadvertently double-counted standby and elective balancing service ("EBS") demands. The Company's adjustments to the design day demand allocator have no impact on the residential and SGS1 design day demands, only a tiny impact on the design day demands for the SGS2 class, but they result in material reductions in design day demands for the SDS, LDS and Flex rate classes. The effect of these changes is generally to shift costs from the rate classes with larger customers (SDS, LGS and Flex) to the smaller customer classes (Residential, SGS1 and SGS2. We have replicated the Company's revised ACOSS, and we include an electronic version of the model as IEc WPS2 in Exhibit IEc-S1.

In our direct testimony, we observed that the Company's design day demands for the Residential and the SGS1 class exhibited a material shift between the Company's last base rates case in 2021 and the current case, without any explanation from the Company for that shift. In rebuttal testimony, Witness Johnson provides some additional detail as to how class-specific design day demands are derived. He generally indicates that the Company has not changed its methodology, and he asserts that the 2022 results are consistent with historical patterns.

Q. In your direct testimony, you expressed a concern that the Company's design day demand forecast, which is provided in the annual Section 1307(f) PGC proceeding, does not explain how it develops class-specific design day demands for use in the ACOSS. Does Witness Johnson provide the detail?

A. As we indicated in direct testimony, the design day forecast for the PGC proceeding is based on forecasting an aggregate design day for all of the smaller customers who are not daily metered, including residential and small/medium non-residential customers. The design day demand for that group is then attributed to individual classes and sub-classes. As we understand it, Witness Johnson appears to indicate that class-specific design day demands are allocated in proportion to the peak month volume forecast for each class.

Q. Is it reasonable to use peak month volumes to allocate design day demands among rate classes?

A. No. Design day demands are intended to reflect class load under extreme weather conditions. Using a volumetric allocator that reflects average January load fails to reflect the weather sensitivity of each class's load under design conditions. Thus, the Company's basic methodology, even without whatever changes it has made in this proceeding, will understate design requirements for customers that are more weather sensitive. Because residential customers are generally more weather sensitive than commercial customers (particularly medium-sized commercial customers), the Company's method has an inherent bias against the commercial rate classes.

Q. Does the Company's argument that peak month volumes are used to allocate design day demands explain the apparent shift in design day demands between Residential and SGS1 rate classes between 2021 and 2022?

A. No, it does not. The data shown in Table IEc-S1 below indicate that peak month loads for the SGS1 class increased a little more between 2021 and 2022 than did the residential loads, but the differential is far too small to justify the material reduction in Residential design day loads and the large increase in SGS1 design day loads. In short, Columbia's data appear to indicate that it has made other changes to its method in 2022, which caused the Residential load factor to decline, and the SGS1 load factor to increase sharply.

Table IEc-S1
2021 to 2022 Comparison: Peak Month and Design Day Demand

	Residential			SGS1		
	2021	**2022**	**%**	**2021**	**2022**	**%**
Peak Month Load (MDth)	5,844.6	6,442.0	10.2%	983.8	1,120.3	13.9%
Design Day Load (Dth/day)	465,000	448,800	-3.5%	77,700	87,000	12.5%

Source: IEc WPS1, Table KLJ-9R

Q. Witness Johnson claims that the class-specific design day demand forecasts are thoroughly vetted in the PGC proceedings, and no party expressed objection to those forecasts in the most recent case. Is that a reasonable defense?

A. No, it is not. In a PGC proceeding, *aggregated* design day demands for sales and Choice customers must be carefully reviewed, to ensure that the Company's upstream pipeline and storage capacity is in balance with design demands. However, *class-specific* design day demands are irrelevant, because no costs are allocated among the various rate classes based on those design day demands. Thus, it would be wasteful for all involved for parties to undertake a detailed evaluation of class-specific design day demands in every PGC proceeding, on the chance that the Company will subsequently file a base rates case and then rely on that analysis. In effect, the Company is taking the position that all parties to Columbia's base rate proceeding have an obligation to actively participate in annual PGC proceedings, and to scrutinize issues that have little or no relevance to those proceedings.

Q. Witness Johnson also presents analysis that indicates that design day demands for the Residential and SGS1 class in 2020 are similar to those from two proceedings back in the 2020 base rates case, and thus the current parameters are consistent with historical patterns. Is that a reasonable argument?

A. In this case, it is not. Witness Johnson's analysis fails to consider a longer-term period, and it fails to adjust the design day demands to overall load shifts. For that reason, we conducted our analysis by comparing class load factors, which reflect changes in both design day demands and overall loads. To address Witness Johnson's argument that a longer-term history purportedly justifies the shift in design day demands and load factors in 2022, we compiled a history of class load factors for the past four proceedings. (Before the 2017 proceeding, the SGS1 and SGS2 classes were not separated.) As shown in Table IEc-S2, the Company's proposed load factor for the residential class is higher than that for any previous year, and the SGS1 class load factor is lower than that for any previous year. Witness Johnson offers no explanation for this apparent shift in design day demand in 2022 away from the residential class and to the SGS1 and (to a lesser extent), the SGS2 class.

Table IEc-S2
Historical Comparative Class Load Factors

	RSS/RDS	SGS1	SGS2
2017 Case	21.3%	19.4%	22.6%
2019 Case	21.1%	22.5%	23.5%
2020 Case	21.0%	20.0%	23.4%
2021 Case	20.4%	19.9%	24.4%
Historical Average	**20.9%**	**20.5%**	**23.5%**
2022 Proposed	**21.4%**	**18.6%**	**22.9%**

Source: IEc WPS1, Table KLJ-9R

Q. Based on this review, what do you conclude regarding the Company's design day demand allocators in this proceeding?

A. We first conclude that the Company's method for allocating design day demand allocators among the rate classes is not reasonable, because it fails to reflect design day conditions. In future base rates cases, the Company should modify its method accordingly.

Second, we conclude that the Company has not justified the material shift in design day demands away from the residential class and to the SGS1 and SGS2 classes that it proposes in this proceeding. We therefore retain the adjustments that we recommended in our direct testimony, and we have incorporated those into the Company's revised ACOSS. Our updated ACOSS is provided electronically as IEc WPS3.

3. Revenue Allocation

Q. What is Witness Mierzwa's response to your direct testimony regarding revenue allocation?

A. Witness Mierzwa agrees with our recommendations that the shortfall from the flex rate customers be allocated among the various rate classes based on the mains allocator, and that percentage rate increases to any particular class should not exceed 2.0 times the system average. Witness Mierzwa opines that we were unduly timid in moving rates into line with allocated cost, and that more progress can be achieved in this proceeding.

Q. Do you agree with Witness Mierzwa?

A. We do.[1] We therefore developed a revised revenue allocation proposal, in which rates for SGS1, SGS2 and SDS classes are moved fully into line with allocated cost (inclusive of the responsibility for the flex rate discounts). As with Witness Mierzwa's proposal, the Residential class will continue to bear most of the shortfall from the LDS class. The primary difference between our revised proposal and that of Witness Mierzwa is that we rely on our revised ACOSS, while Witness Mierzwa has not accepted our proposed changes to the design day demand allocators. Our revised revenue allocation proposal is shown in Table IEc-S3 below and is detailed in IEc WPS3.

---

[1] We trust that OCA will support similar proposals to aggressively move rates into line with allocated cost when higher increases are appropriate for the Residential class.

Table IEc-S3

Summary of IEc Surrebuttal Revenue Allocation Proposal

	Increase $mm	Increase %	R/C Current	R/C Proposed	"Progress"
Residential	$48.86	11.6%	106.1%	103.7%	39%
SGS1	$ 6.87	14.3%	99.9%	100.0%	100%
SGS2	$10.99	21.9%	93.6%	100.0%	100%
Med Gen'l (SDS/LGSS)	$ 8.53	28.4%	88.4%	99.4%	95%
Lg Gen's (LDS/LGSS)	$ 6.78	28.4%	56.0%	63.0%	16%
MDS	--	0.0%	1333.7%	1167.9%	13%
Flex	$ 0.01	0.3%	NM	NM	NM
Total	**$82.06**	**14.2%**	**100.0%**	**100.0%**	--

Flex rate cost performance is not meaningful because $40 million shortfall is reallocated to other rate classes.

Source: IEc WP3

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

EXHIBIT IEc-S1

IEc ELECTRONIC WORKPAPERS

IEc WPS1 – Design Day Demand Workpapers

IEc WPS2 – Replication of Columbia Rebuttal COSS

IEc WPS3 – IEc Alternative Surrebuttal COSS

Electronic workpapers in excel format will be distributed via email attachments simultaneous to service of Surrebuttal Testimony

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**Docket No. R-2022-3031211**
	:	
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	
	:	

VERIFICATION

I, Mark D. Ewen, hereby state that the facts set forth in the Surrebuttal Testimony labelled OSBA Statement No. 1-S and associated Exhibit IEc-S1 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: July 26, 2022

Mark Ewen
Mark D. Ewen

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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v.	:	**Docket No. R-2022-3031211**
	:	
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

VERIFICATION

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Date: July 26, 2022

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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Phillip D. Demanchick, Jr., Esquire
Hawke McKeon & Sniscak LLP
100 North Tenth Street
Harrisburg, PA 17101
tjsniscak@hmslegal.com
wesnyder@hmslegal.com
pddemanchick@hmslegal.com

Amy E. Hirakis, Esq.
Theodore J. Gallagher, Esq
Columbia Gas of Pennsylvania, Inc.
800 North 3rd Street, Suite 204
Harrisburg, PA 17102
tjgallagher@nisource.com
ahirakis@nisource.com

Erika McLain, Esq.
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120
ermclain@pa.gov

Charis Mincavage, Esquire
Kenneth Stark, Esquire
McNees Wallace & Nurick LLC
100 Pine Street
Harrisburg, PA 17101
cmincavage@mcneeslaw.com
kstark@mcneeslaw.com

Todd S. Stewart, Esquire
Hawke McKeon & Sniscak LLP
100 North Tenth Street
Harrisburg, PA 17101
tsstewart@hmslegal.com

Michael W. Hassell, Esquire
Lindsay A Berkstresser, Esquire
Post & Schell PC
17 North Second Street
12th Floor
Harrisburg, PA 17101-1601
mhassell@postschell.com
lberkstresser@postschell.com

Lauren E. Guerra, Esq.
Barrett C. Sheridan, Esq.
Harrison W. Breitman, Esq.
Darryl A. Lawrence, Esq.
Office of Consumer Advocate
555 Walnut Street
5th Floor Forum Place
Harrisburg, PA 17101-1923
lguerra@paoca.org
BSheridan@paoca.org
HBreitman@paoca.org
abeatty@paoca.org

Joseph L. Vullo, Esquire
Burke Vullo Reilly Roberts
1460 Wyoming Avenue
Forty Fort, PA 18704
jlvullo@bvrrlaw.com

The Honorable Christopher P. Pell
Deputy Chief Administrative Law Judge
Commonwealth of Pennsylvania
Pennsylvania Public Utility Commission
801 Market Street, Suite 4063
Philadelphia, PA 19107
cpell@pa.gov

Jennifer E. Clark, Esq.
Fair Shake Environmental Legal Services
100 S. Juniper St.
3rd Floor
Philadelphia, PA 19107
jclark@fairshake-els.org

Andrew Karas
Mark Szybist
Natural Resources Defense Council
1152 15th St. NW, Suite 300
Washington, DC 20005
akaras@fairshake-els.org
mzybist@fairshake-els.org

Lafayette Morgan
Exeter Associates, Inc.
10480 Little Patuxent Pkwy, Suite 300
Columbia, MD 21044-3575
OCAColumbiaGas2022@paoca.org

Roger Colton
Fisher, Sheehan & Colton
34 Warwick Road
Belmont, MA 02478
OCAColumbiaGas2022@paoca.org

David Garrett
Resolve Utility Consulting PLLC
101 Park Avenue, Suite 1125
Oklahoma City, OK 73102
OCAColumbiaGas2022@paoca.org

John W. Sweet, Esq.
Ria M. Pereira, Esq.
118 Locust Street
Harrisburg, PA 17101
717-710-3839
pulp@palegalaid.net

James L. Crist, P.E.
Lumen Group, Inc.
4226 Yarmouth Drive, Suite 101
Allison Park, PA 15101
JLCrist@aol.com

Constance Wile
922 Bebout Road
Venetia, PA 15367
cjazdrmr@yahoo.com

Jose A. Serrano
2667 Chadbourne Drive
York, PA 17404
jas673@hotmail.com

Richard C. Culbertson
1430 Bower Hill Road
Pittsburgh, PA 15243
richard.c.culbertson@gmail.com

Jerome Mierzwa
Exeter Associates, Inc.
10480 Little Patuxent Pkwy, Suite 300
Columbia, MD 21044-3575
OCAColumbiaGas2022@paoca.org

James L. Crist, P.E.
Lumen Group, Inc.
4226 Yarmouth Drive, Suite 101
Allison Park, PA 15101
JLCrist@aol.com

Honorable John Coogan
Administrative Law Judge
Pennsylvania Public Utility Commission
Office of Administrative Law Judge
400 North Street
Harrisburg, PA 17120
jcoogan@pa.gov
sdelvillar@pa.gov

/s/ Steven C. Gray

DATE: July 26, 2022

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Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538